



**GAS LIFT OPTIMIZATION UTILISING
AUTUMATION GAS LIFT VALVE**

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ABSTRACT

Gas lift is one of the most common forms of artificial lift, particularly for offshore wells. This is due to its relative downhole simplicity, flexibility, reliability, and ability in operating over a wide range of flow rates with the limited well head space. Generally, Gas lift optimization can reduce the operating cost with increase in the Net Present Value (NPV) and maximization of the recovery from the asset.

All of the previous researches have reported that conventional gas lift technologies' designs have limitations on gas lift valve. Nonetheless, traditional gas lift technologies that were designed and developed in 1950's do not have resistance when subjected to high temperature and high pressure in subsea wells. This therefore unable the flows of the gas lift to be coherently controlled. Moreover, gas-lifted oil wells can lead to failure unless a smart gas lift valve unit is used in the controlling the amount of the gas inside the tubing string.

In this study, an automation gas lift valve unit with the corresponding control line was experimentally simulated on a dedicated apparatus. This enables real-time data on the gas lift valve to the surface to be demonstrated and accordingly analyzed. Under the conventional method of practice the injection pressure of the gas is normally used in operation of the valve. Whereas in this investigation the port size of the gas lift valve was remotely adjusted from the assumed surface using the apparatus. A devoted computer program LabVIEW was also used in determination of the gas passage through the smart gas lift valve, thus distilling the real time data. The results have shown those optimizations are achievable at high gas injection pressure when 87 psi is used and when the valve is 15% open (or 0.95mm port size diameter). Also, the wellhead pressure reaches to the minimum value of 0.9 psi in which high-pressure drop between the reservoir pressure and the top surface will occur.

Throughout this investigation, water was used as a working fluid since the column of corresponding water in petroleum production tubing has the highest hydrostatic pressure of 2.8 psig compared with crude oil. Hence, during the gas lift process crude oil will be less cumbersome to produce than water.

The results present the maximum production rate of 18.3 lit/min (with 83% improvement on production) could be achieved. The results obtained experimentally were also used in constructing an economic analysis from the use of smart gas lift valve for different scenarios namely: (i) in gas lift natural flow and (ii) the gas lift wells. It was demonstrated that the flow rate can be enhanced from 91bbl/day to 166.5 bbl/day for the gas lift natural flow, and from 'Zero' (or non-production) to 165.6 bbl/day for the gas lift well. Based on these results, the NPV of the gas lift natural flow will be approximately \$2793 on \$37 per barrel and for the gas lift well will be about \$6127.2

DECLARATION

I, Mohamed Ali Elghadban Abdalsadig, declare that this dissertation report is my original work, and has not been referred to elsewhere for any award. Any section, part or phrasing that has been used or copied from other literature or documents copied has been clearly referenced at the point of use as well as in the reference section of the thesis work.

Date: / / 2017

Signature

DEDICATED

First of all I would like to thank my wonderful family for their sincere moral support and for being with me through both the good and the hard times during these years. Without their support this work would not have been possible. Thanks to my mother for her support, my brothers, and sisters, my wife, my sons; Abdalwadwad, Abdellmyemen, and my daughters; Rauan, Roa and Rahaf.

LIST OF PUBLICATIONS

The research work towards this thesis led to in the following publications:

- M. A. GH. Abdalsadig, Amir Nourian, G. G. Nasr, “Gas Lift Optimization to Improve Well Performance, In International Journal of, Manufacturing Engineering Aerospace, Industrial, Mechatronic Mechanical, and Vol:10, No:3, 2016., 2016, vol. 10, no. 3, pp. 419–427.
- M. A. GH. Abdalsadig, A. Nourian, G. G. Nasr, and M. Babaie, “Gas Lift Optimization Using Smart Gas Lift Valve,” Int. J. Mech. Aerospace, Ind. Mechatron. Manuf. Eng. Vol10, No6, 2016, vol. 10, no. 6, pp. 1062–1067, 2016.
- M. A. GH. Abdalsadig, A. Nourian, G. G. Nasr, and M. Babaie, “Real-time Gas Lift Valve to Enhance Well Performance.,” J. Pet. Eng. Technol. 2016; 6 (2), vol. 6, no. 2, pp. 1–10, 2016.

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CONVERSION TABLE

Parameter	SI	Other Conversion Factor
Pressure	101.325KPa	1atm
		1.01325Par
		0.101325Mpa
		101325Pa
Flow	1m ³ /s	35.32ft ³ /s
		219.96gal(UK)/S
		1000 L/s
		543439BOPD
Length	1m	1000 mm
		0.001km
		3.28ft
		39.37in
Temperature	⁰ C	32 ⁰ F
		273.15K
		492R

LIST OF SYMBOLS AND ABBREVIATIONS

Ab	Area of the Bellows
An	Cross Section Area of Annulus
ANL	Analysis Natural Lift
Ap	Area of the Portion of the Stem Tip
Ap/Ab	Ratio of Port Area to Bellows Area
API	American Petroleum Institute.
BHP	Static Bottom-Hole Pressure
BPD	Barrel Per Day
BWF	Flowing Bottom-Hole Pressure
Cd	Discharge Coefficient
CgT	Gas Gravity and Temperature Correction Factor
CITHP	Tubing Head Pressure
D1	Orifice Internal Diameter/size for a Known Volumetric Gas Rate (in.)
D2	Orifice Internal Diameter/Size for an unknown Volumetric Gas Rate
DEA	Aqueous Alkanol Amine
ESP	Electric Submersible Pump
Fcf	Critical Flow Pressure Ratio
Fdu	Pressure Ratio (P_2/P_1) for Non-Critical Flow

FLP	Flowing Level Pressure
G	Gravitational Acceleration (ft. /sec ²)
GLR	Gas Liquid Ratio
GLV	Gas Lift Valve
GLW	Gas Lift Well
GOR	Gas Oil Ratio
HES	Health, Environment, and Safety
HL	Liquid High in the Annulus
HP	High Pressure
HP	High Pressure
HT	High Temperature
ICV	Intelligent Control Valve
IPM	Integrated Production Model
IPO	Injection Pressure Operated Valve
IPR	Inflow Performance Relationship
IPR	Gas Lift Performance Relationship
K	Specific Heat Ratio (C_p/C_v)
KOT	Kick Over-Tool
KPM	Key Performance Monitoring
Kv	Valve Constant
MBAL	Material Balance Analysis
Mscf/D	Million Standard Cubic Foot per Day
NFW	Natural Flow Well

P. Res.	Reservoir Pressure
P1	Orifice Upstream Gas Pressure
P2	Orifice Downstream Gas Pressure
PA	Production Allocation
Pb	N2 Charged Bellow Pressure
PbvD	Pressure of N2 Charged Bellows
Pc	Pressure Casing
PDG	Permanent Down Hole Gauge
PI	Productivity Index
PioD1	Pressure of the Injection Gas at Valve Depth
PL	Production Losses
PLC	Programmable logic control
PoD1	Initial Valve Opening Pressure of the Injection Gas
PPDG	Pressure Measured in PDG
PPO	Fluid Pressure Operated Valve
PROSPER	Production and System Performance
Pt	Pressure Tubing
PTPT	Pressure Measured in TPT
Pvo	Opening Pressure of the Test-Rack
PVT	Pressure Volume Temperature
Qg1	Known Volumetric Gas Rate (Mscf/d)
Qg2	Unknown Volumetric Gas Rate (Mscf/d)
Qga	Actual Volumetric Gas Flow (Mscf/d)

Qgc	Volumetric Gas Flow from Chart Readings
Qgsc	Gas Flow Rate (Mscf/d) – 14.7 psia; 60°F
R & D	Reporting and Distributing
RVA	Reservoir Visualization and Analysis
SPS	Smart Production Surveillance
T1	Upstream Gas Temperature
TC	Thornhill craver
TC	Time Cycle
TgD	Gas Temperature (°R) @ Valve Depth
TI	Time Injection
TPT	Temperature and Pressure Transmitter
USB	Universal Serial Bus
W.H.P	Well head Pressure
WPE	Well Performance Evaluation
γ_o	Oil Specific Wight

CHAPTER 1

INTRODUCTION

1.1 Background

Once the oil is first found in the reservoir, it is below pressure from the natural forces that surround and trap it. If a well hole is drilled into the reservoir, an opening is provided at a much lower pressure through which the reservoir fluids can escape. The driving force that causes these fluids to travel out of the reservoir and into the wellbore comes from the compression of the fluids that are stored in the reservoir. The actual energy that causes a well to produce oil results from a reduction in pressure between the reservoir and the producing facilities on the surface.

Reservoir pressure declines over the time and consequently, production rate drop. Gas lift is used to increase oil production rates or to permit no flowing wells to flow by reducing the hydrostatic head of the fluid column in the well. Furthermore, gas lift systems can be used to maintain tubing head pressure in subsea wells and also mitigate the effects of high water cut. Gas injected into the hydrostatic column of fluid decreases the column's total density and pressure gradient, allowing the well to flow. (As the tubing size increases, the volume of gas required to maintain the well in a flowing condition increases as the square of the increase in tubing diameter). If the volume of the gas lifting the oil is not maintained, the produced oil falls back down the tubing, and the well suffers a condition commonly known as "loading up." If the volume of gas is too much, the cost of compression and recovery of the lift gas becomes a significant percentage of the production cost. As a result, the size of a gas injection orifice in the gas lift valve is of crucial significance to the stable operation of the well.

Conventional gas lift systems pump gas down the annulus from the surface and need a considerable investment in sub surface equipment such as a gas lift valve, mandrel types and surface facility such as compressors, pipeline etc.

A simplified diagram of this particular gas lift system shows in Figure 1.1 from the bottom- hole to the point of gas injection; the well is flowing with the natural formation gas-liquid ratio (FGLR) and from the point of injection up to the surface. The well is being gas lifted and flows with gas lift (GLR). The point of injection indicates the capability of the reservoir to produce fluid matching the capability of the tubing to take out fluids.

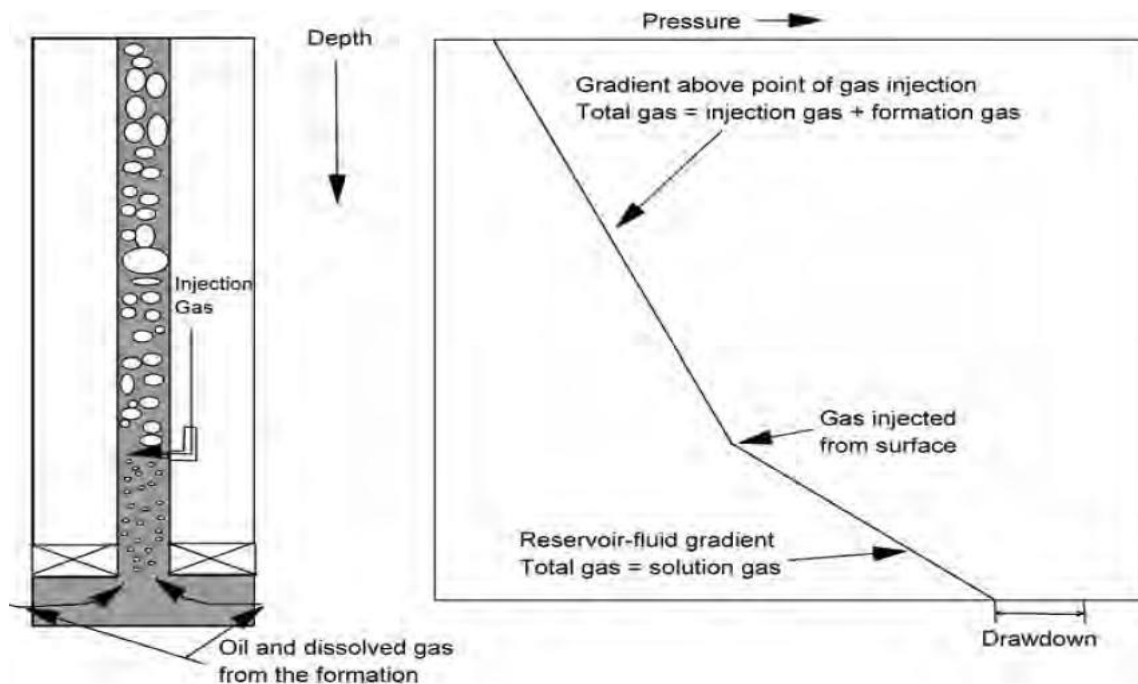


Figure 1.1: Gas Lift System [1]

1.2 Gas lift valve

Gas lift valves are the means by which operators adjust the rate of gas injection into the liquid column in the production tubing. Check valves within the gas lift valves allow flow in only one direction- from the casing annulus into the production tubing. For maximum

efficiency, gas lift valves are staged as deeply in the well as possible, setting depth is limited by available injection pressure. Injection pressure operated gas lift valves are designed to open typically in reaction to a specified gas pressure in the casing annulus. There are many types of the gas lift valves in the oil industry. Injection pressure operation valves are the most common one. Injection pressure operated gas lift valves, placed at various depths in the well and open in response to a present level of pressure exerted by the production fluid column. They remain closed unless the well experiences an increase in fluid in the tubing, at which point they open to assist in the lift the excess fluid from the well[2]. Furthermore, the valve is latched into the side pocket one can pull on the wire line with a predetermined force or activate the stroker and additional pin will shear, freeing the running tool from the gas-lift valve. Further pulling on wire line or activation of stroker will shear another pin in the kick out tools (KOT). The tool string can then be pulled out of the well. Figure 1.2 shows the running process. The sequence of pulling a valve is identical, with a pulling tool changing the running tool [3].

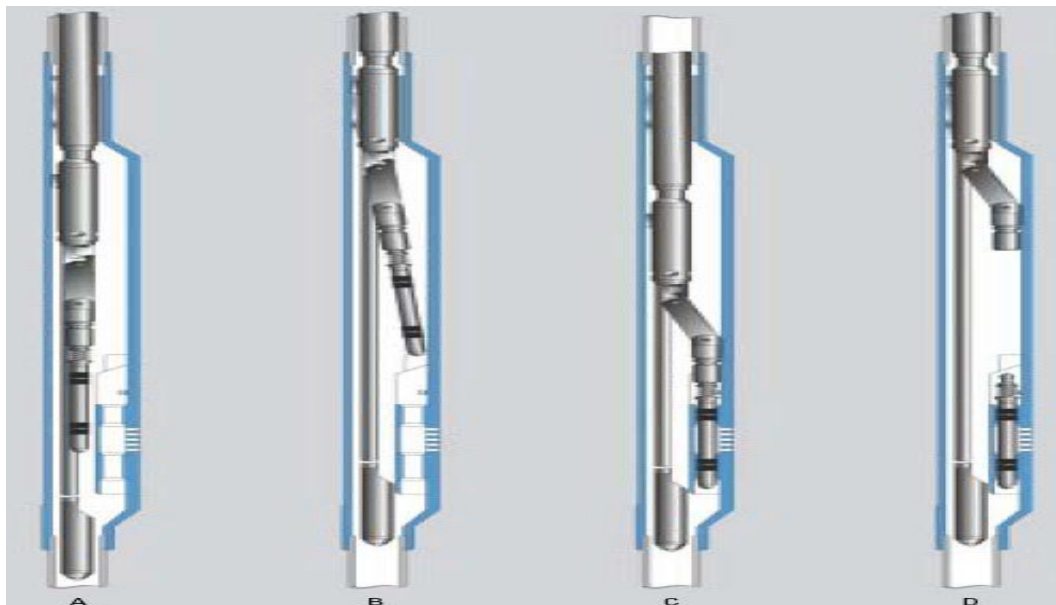


Figure 1.2: Valve Installation with KOT [3]

1.3 The Gas Lift Surface Components

Gas-lift System Components

The primary components of the gas-lift production system are:

- Surface gas-lift compression, dehydration, and distribution system;
- Gas injection metering and control equipment;
- Gathering system—flow line and manifold;
- Well production rate testing facility;
- Production handling system

The Gas Lift Subsurface Components:

Figure 1.3 shows the basic gas lift components

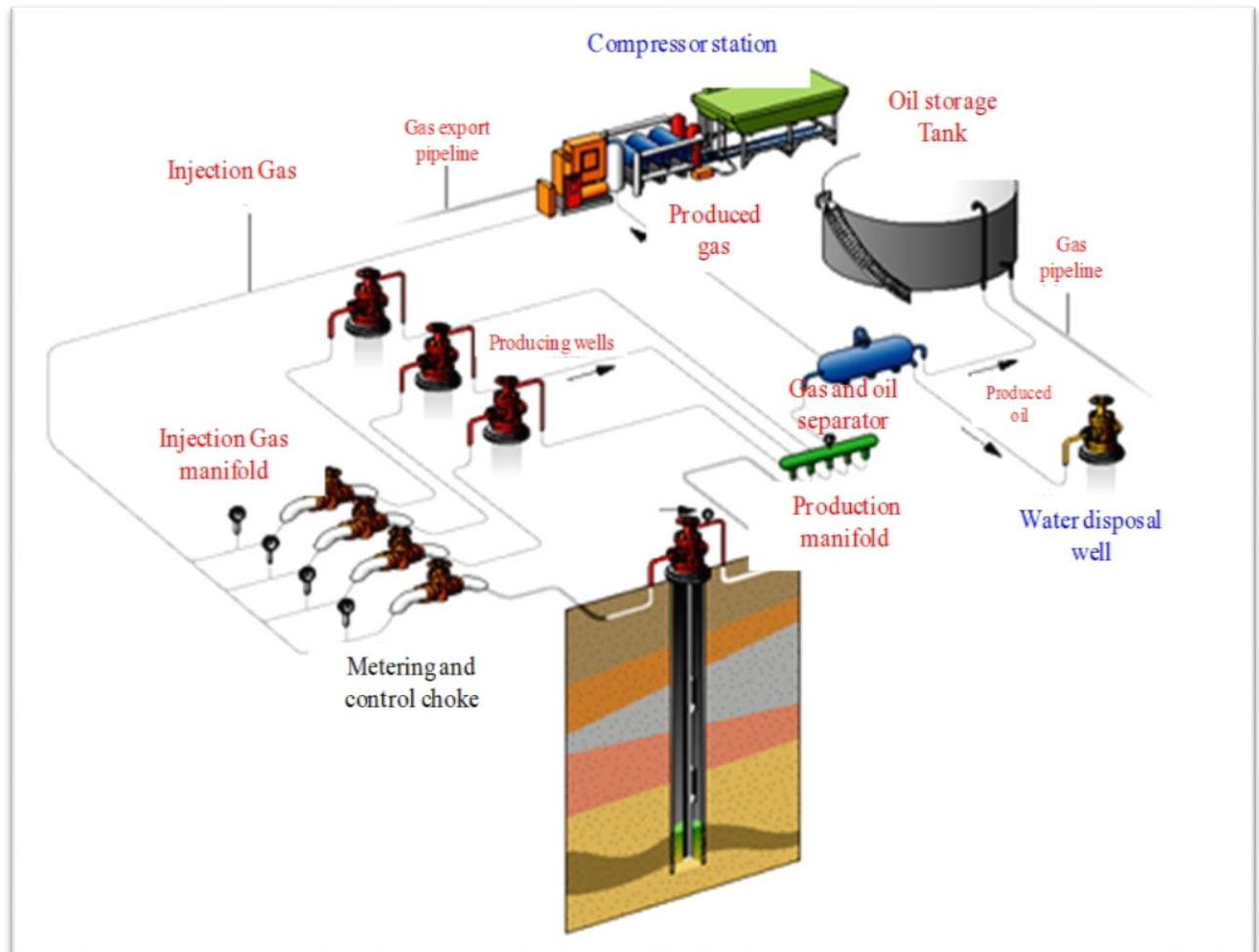


Figure 1.3: The Basic Gas Lift Components[4]

1.4 Contribution to Knowledge

To investigate the replacement of the current conventional injection pressure valve in the 'Natural Flow Well' and 'Gas lift Well' by the 'smart gas lift valve' that allows the port size of the valve to be remotely adjusted from the surface in increasing the production rates.

1.5 Aims

- i. To develop automation gas lift valve unit that connects with the control line that provides real information to the surface instead of an intrusive conventional injection pressure valve.

1.6 Objectives

- i. To construct a laboratory experimental apparatus to evaluate the gas lift wells performance under realistic operations in measuring the reservoir pressure; the production operation point, injection gas pressure, port size and the effect of injection pressure on well performance
- ii. Undertake a two-phase flow experimental to investigate the effect of gas injection rate on well head pressure under different gas lift valve port size by using an automation gas lift valve
- iii. To carry out the economic analysis using the automation gas lift valve

1.7 Structure of the Research Thesis

The thesis is arranged in chapter's forms, with each chapter giving a set of information and actions performed as contained in the research work as follows:

Chapter 1: Introduction

This chapter gives a general insight into the gas lift technique; also, the Chapter highlights the mains and objectives of the research.

Chapter 2: A Literature Review of Gas Lift Technique

This chapter presents a general background and an overview to some of the relevance on the subject of gas lift technique. This chapter also gives a literature survey of an overview of previous work regarding an automation gas lift system will be a briefly described. Furthermore, this chapter gives an extensive overview of utilization of 'Smart' Systems on Well Technology also, the theory and concept in gas lift optimization will be given in this Chapter.

Chapter 3: Experimental Apparatus and Method for Data Processing

This chapter presents the experimental design, set-up, and apparatus of the research experiment. Furthermore, the experimental procedure and measurement techniques that were used to investigate the automation gas lift are also described

Chapter 4: Experimental Results and Discussion

This Chapter presents the experimental results and discussions of the effect of the injection pressure in the production rate performance

Chapter 5: Conclusions and Future work: This Chapter provides the conclusions from this study and suggestions for the future work

CHAPTER 2

A LITERATURE REVIEW OF GAS LIFT TECHNIQUE

2.1 Overview

As worldwide energy demand continues to grow, oil and gas fields have spent hundreds of billions of dollars to build the substructures for the smart field. Management of smart fields requires integrating knowledge and methods to automatically and autonomously handle a great frequency of real-time information streams gathered from the smart wells. Furthermore, as oil businesses move towards enhancing everyday production skills and meeting global energy demands, it signifies the importance of adapting to the latest smart tools that assist them in running their daily work.

Oil production from depleted reservoirs with insufficient energy often requires an artificial method to lift fluids from the bottom hole to the surface. Sucker rod pump, electric submersible pump and gas lift are the most common artificial lift methods used to lowering the bottom-hole pressure and providing the lift energy to raise the fluids to the surface [5].

The purpose of artificial lift is to keep a reduced producing bottom- hole pressure (BHP) so the formation can give up the anticipated reservoir fluids. A well may be accomplished by performing this task under its individual power. In its last phases of flowing life, a well is capable of producing only a fraction of the desired fluids. Throughout the period when a well is flowing and particularly afterward the well dies, an appropriate means of artificial lift must be connected so the required flowing BHP can be upheld.

In gas lift methods, a compressed gas is injected at a high pressure in the annulus which lightens the fluid column by reducing its density and pressure losses. The presence of gas inside the production tubing at the deepest point reduces the flow pressure of the bottom-hole to allow fluid to flow from reservoir to the surface. The goal of gas-lift is to deliver the fluid to the top of the well head while keeping the bottom-hole pressure low enough to provide high-pressure difference between the reservoir and bottom-hole (BHP). Reduction of bottom-hole pressure due to gas injection will normally increase the liquid production rate. However, injecting high amount of gas will increase the bottom-hole pressure which will lead to the decline of the production flow rate. The optimum design of gas lift system is depends on the critical combination of quantity of pertinent variables, including gas lift valve performance, reservoir pressure, water cut, productivity index, gas oil ratio, tubing size and injection gas pressure. The economic performance of the optimum design is dependent upon maintaining a minimum injection gas rate which leads to improving oil production rate [6].

The determination of gas passage through a certain valve is the most important factor of gas lift string design. The main criteria for an unloading valve is that it will permit sufficient gas to unload the well to the extent that the next (lower) valve can be uncovered, and that it will close and remain closed once lift gas is injecting deeper in the tubing string. There are many types of gas lift valves available on the market. Some are designed for use in the continuous gas lift, some for intermittent lift. Both types are manufactured for either tubing flow or annular flow. The closing force in some valves is generated by nitrogen pressure enclosed in a chamber within the valve. In a traditional gas lift system, the tubing is fitted with a side pocket mandrel, where the side pocket can have a gas lift valve; the gas-lift valve can be pre-installed or placed in the side pocket by means of wire line. These

technologies have design limitations on gas lift valve such as multi-point of injection, nitrogen charge also, pressure operated valve is very sensitive to well performance condition such as pressure, temperature and casing pressure. This research investigates the replacement of the present conventional injection pressure valve in the oil production field by the 'smart gas lift valve' that allows the port size of the valve to be remotely adjusted from the surface and continuous injection gas into the downhole that will lead to improving the production rates.

2.2 Types of Gas Lift System

There are two types of gas lift flow. Intermittent flow and continuous flow[7].The understanding of these two types of the gas lift is important with regards to the present investigated in which it can highlight where the Smart Gas lift will be suited in the real gas located well. In this study, continuous flow gas lift type will be used. Because continuous gas lift is also called constant flow gas lift and it is a steady-state flow. Continuous gas lift is mainly applied in the high PI and high bottom-hole wells. In this type, production rate varies between 100 to 30000 bopd. In continuous gas lift flow a small volume of gas is required to be injected. Therefore, it would be better to install valves as deep as possible to lighten much liquid. Continuous gas lift is the best application for the reservoirs with water drive or water flooding. This type is better for high GOR wells. As was stated above, in high GOR wells only a small volume gas will be required to contribute to the formation gas to lighten the fluid column and increase production rate. But in this type of gas lift, gas supply must be maintained throughout the life of the well. As water cut increases in the well gas production will decline. In this case, much gas will be required to be injected in order to achieve the desired depth. Because, poor gas supply even could stop the production.

2.2.1 Continuous Flow Gas Lift

Figure 2.1 shows the continuous gas lift system. In the continuous gas lift, the gas always passes through the operation valve forming a homogenous combination of liquid and gas overhead the injection point.

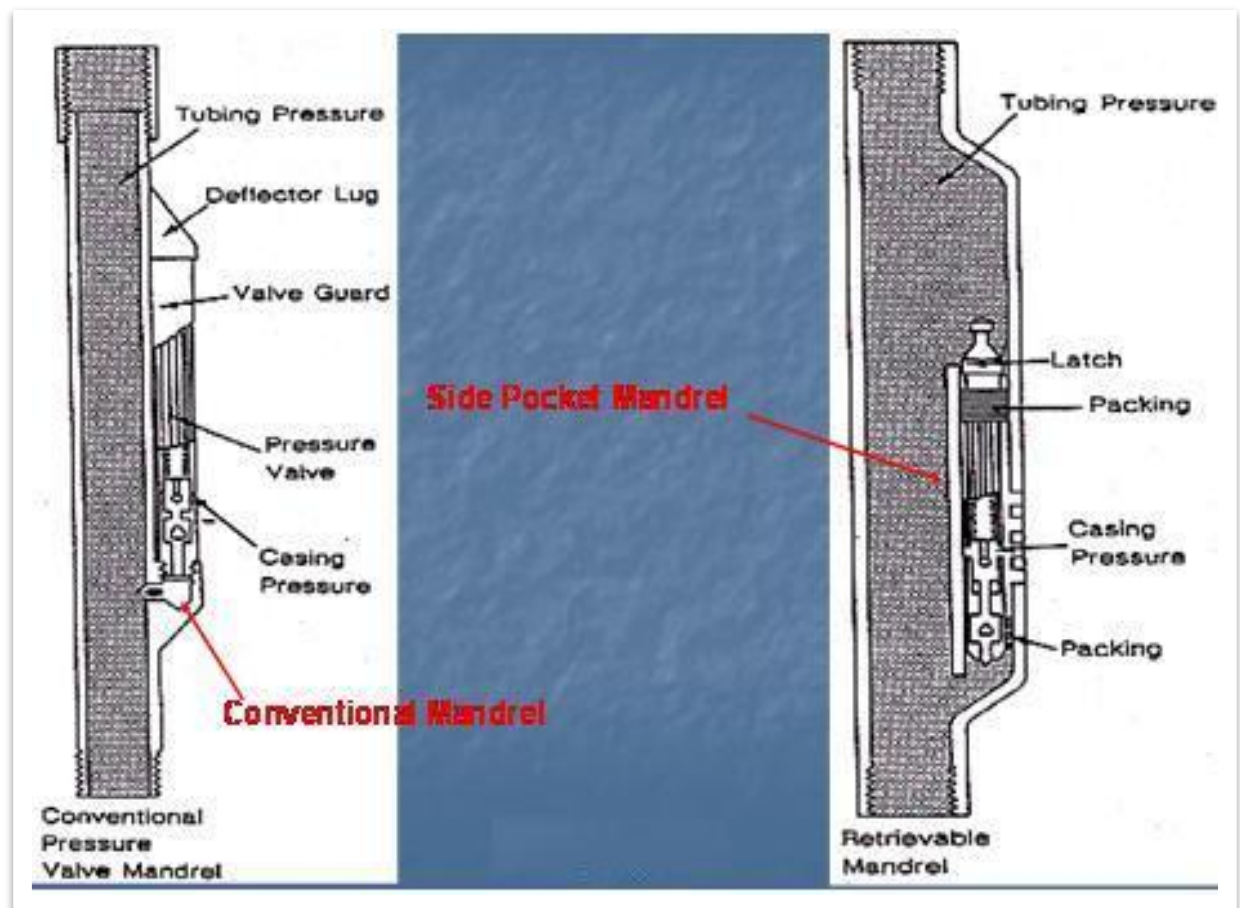


Figure 2.1: the continuous gas lift system [8]

The continuous gas lift is used when the well has a high productivity index.

In the continuous flow gas lift, gas is injected at a depth that permits efficient aeration from the point of injection to the surface. The aeration of the fluid decreases the weight of the column (decrease in liquid density), and thereby reduce the BHP to the level required to provide continuous flow from the well. This injected gas joins the formation gas to lift the fluid to the surface by one or more of the following processes:

- Reduction of the fluid density and the column weight so that the pressure differential between reservoir and wellbore will be increased.
- Expansion of the injection gas so that it pushes liquid continuous flow gas lift ahead of it which further reduces the column weight, thereby increasing the differential between the reservoir and the wellbore.

Determination of gas passage through a selected valve is an important part of gas lift string design. The major problem most operators encounter with continuous gas-lift is maintaining an optimum gas injection rate into each well and through down-hole gas lift valves. The required injection gas volume is usually controlled by one (or more) orifices in the valve, and by the movement of the ball and stem. The selection of the correct orifice size is usually carried out with the help of charts supplied by the manufacturer.

2.2.2 Intermittent Flow Gas Lift

Figure 2.2 illustrates the intermittent gas lift system. In the intermittent gas lift, the gas is injected in cycles, allowing the reservoir to transport a quantity of fluid forming column overhead to the point of injection. In the intermittent flow system, fluid is permitted to accumulate and build up in the tubing at the end of the well. Periodically, a huge bubble of great pressure gas is injected through the tubing very quickly underneath the column of liquid and the liquid column is pressed rapidly up the tubing to the surface. The frequency of gas injection in the intermittent lift is determined by the amount of time required for a liquid slug to permit in the tubing. The distance of the gas injection period will depend upon the time required to drive one slug of liquid to the surface [9].

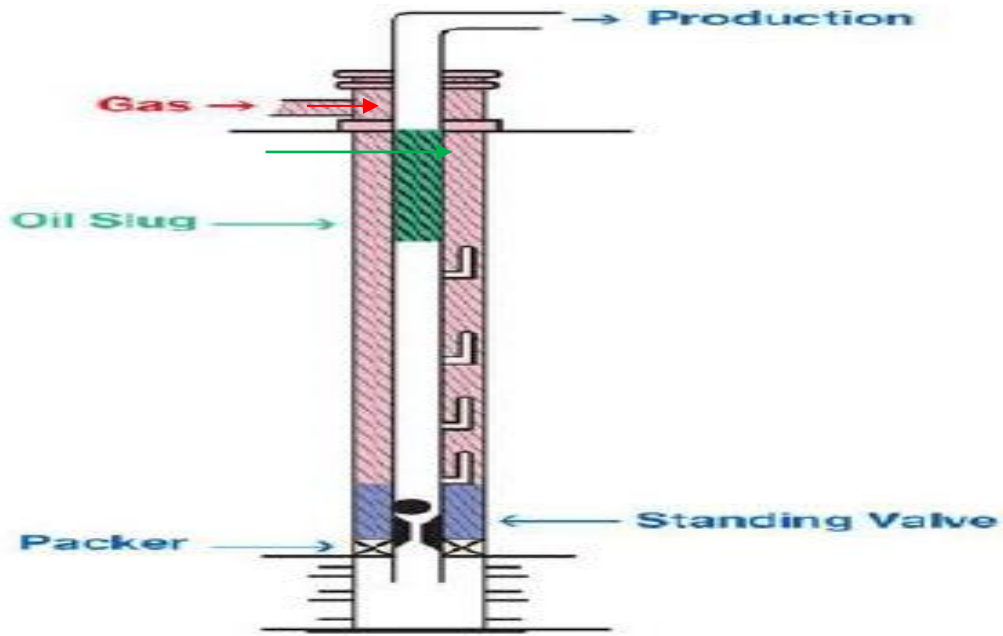


Figure 2.2: Intermittent Flow Gas Lift [10]

Kirkpatrick,[11] reported that, explained the state of the art of design of injection gas lift approaches and gave a clear consideration for the design of the production rate, and a procedure to select the greatest injection gas lift and presented some experimental outcome on specific field installation of conventional injection gas lift. They determined particular experimental procedures for the setting of the operational limitations [12].

Garcia, et al.[13]. Developed an unloading procedure that controls the liquid flow rate through gas lift valve and focused on the erosion problems, thus aiming to limit the liquid velocity inside the valve. In order to find the greatest acceptable gas injection pressure during unloading and to avoid erosion of the gas lift valve by liquid flow rate. (The method was designed for offshore gas lift wells due to its high intervention costs to change damage valves by erosion that decreases the maximum flow rate and cause production instabilities particularly for the wells that are completed without a packer. An eroded gas lift valve can be seen in Figure 2.3[13].

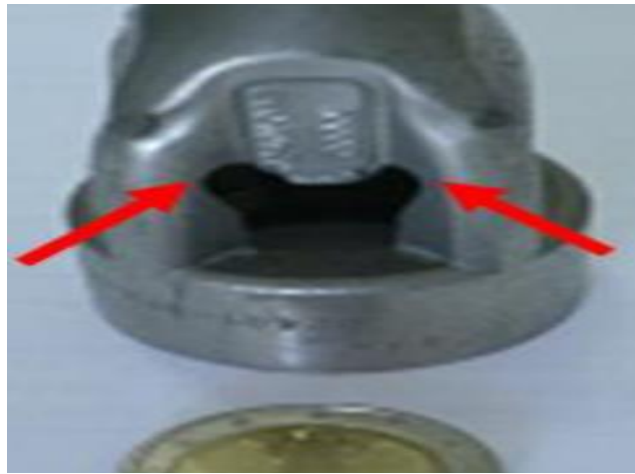


Figure 2.3: Erosion Caused by High Liquid Flow Rate [13]

A large number of gas lifted wells around the world are under-performing. Most commonly it is due to ‘multi-pointing’, where instead of all the lift gas being injected via the operating valve at the planned injection depth, some (unintentionally) enters the tubing via one or more of the shallower unloading valves. In other cases, wells may underperform as the planned injection depth cannot be reached with the available lift gas pressure. These issues are often the result of unloading valve reliability problems or inadequate gas-lift design [14]. Injecting high amounts of gas raises the bottom-hole pressure that leads to a reduction of the production rate. This is due to the high gas injection rate that causes slippage. In this case, the gas phase moves quicker than the liquid phase, leaving the liquid phase behind and a smaller amount of liquid will flow along the tubing. Therefore, there should be an optimum gas injection rate [15]. Unfortunately, conventional gas lift technologies have design limitations on the gas lift valve, Nonetheless, traditional gas lift technologies, mostly have been developed in 1950s, they do not meet all of the high temperature and pressure requirement. Lift gas flow is not actively controlled, however, it

was suspected that stability could be brought to the unstable well [16]. Julian et al [17] discussed a history of the gas lift valve and gas lift mandrel damage and subsequent retrofit gas lift straddle that was installed in the Alaskan oil field which is the largest gas lift in the world and also provided a systematic approach to their design and deployment. The results showed that the main source of tubing communication was associated with the gas lift operation. Figure 2.4 illustrates that damaged gas lift mandrels account for 42% damaged gas lift valves account for 12% and the tubing leaks accounted for 28% of annular communication mechanism [18].

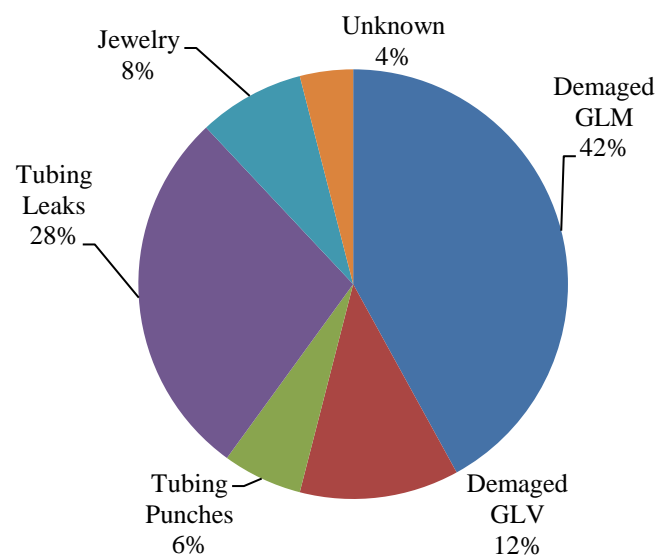


Figure 2.4: The Damage Associated with Gas Lift Operation [17]

Avest *et al.*[19] reported that traditional gas lift system, lift gas flow is not completely controlled. Nevertheless, it was suspected that stability might be brought to the unsteady well by utilizing a control valve to precisely adjust its gas flow. The best gas lift applications use an injection pressured operation valve to regulator lift gas to the well. This means that most engineers can only guess the flow rate being delivered to the bottom of the well. They do not have the ability to correctly control it. Some people incorrectly trust

that valves control flow. If a valve is set to a certain point, the predicted rate of flow is only kept when the differential pressure, or the difference between the upstream and downstream pressure, is continuous. This is infrequently the case, even though the well's gas lift header pressure is relatively constant and the pressures within the well vary extensively. Subsequent excessive swings in the lift gas flow rate mainly show in fields with a huge number of wells. It is difficult for engineers to effectively monitor gas lift performance of each individual well to identify current or potential difficulties, take corrective measures, and identify optimization opportunities that will yield the largest returns. The aim of real-time gas lift surveillance, analysis, and optimization is to present the engineer at any point in time, an understanding of how the gas lift valves are performing. This will empower them to make the changes necessary to ensure that the well is steady and injecting into the orifice [19].

Elldakli, *et.al* [20]. Injection operated GLV often does not open fully in actual operation an efficient gas lift technique is directly related to an increased production rate. Therefore, the proper selection of a gas lift valve is of significant importance in the recovery process. However, by using the smart valve systems that were simulated and tested in the present study, the issues raised by these previous authors can be resolved.

The proper function of gas lift valves is very important for the safety of the well and surface operations. If hydrocarbons flow through the incorrect path (i.e. backflow from the tubing into the annulus, through a gas lift valve leakage), they can reach the wellhead and create an undesired accumulation of high-pressure combustible material. Incorrect manipulation of surface valves, procedures, and accumulation of gasses is thought to have caused the 1988 accident on the Piper Alpha North Sea production platform, which led to an explosion and fire killing 167 men [21]. The proposed, gas lift valve monitoring from

the surface will improve the well performance as well as the safety of the well. The smart gas valve will close from the surface to prevent and leakage that may causes explosion.

Arellano et al.[22] Described the dynamic, real-time workflow for gas lift surveillance and troubleshooting to identify the ways to optimize gas lift performance. The software which was used innovatively use of dynamic visualization, mathematical models and real- time. The program estimated the stability condition of gas lift wells with a single point of injection or multiple valves. A number of case studies were described using workflow logic in order to improve the gas lift performance. It was very valuable for the production engineer to get data from a database in real time and be able to visualize the dynamical variation which may improve the stability of the well [22].

2.3 Utilization of Automation Systems on Well Technology

Operating a gas-lift under low or high gas-lift injection rate has some disadvantage. First, the full lift potential in the gas is not accurately used, resulting in a very inefficient operation. Secondly, pressure surges in production facilities may be so huge that severe operational problems are likely to happen. Moreover, production control becomes very difficult. Well performance analysis is a combination of various components of oil or gas wells in order to predict flow rates and to optimize the various components of the system. A variety of issues can impact the performance of gas-lift wells. These issues are frequently classified as either inlet/outlet issue or down hole issue [23]. The gas injection rate through gas lift valve must be controlled to be sufficient to obtain and maintain critical flow, also, gas lift valves must be designed not only to allow gas passage through it and prevent oil passage but also for gas injection into wells to be started and stopped when needed. In this research, automation gas lift valve has been used to investigate the effect of the valve port size which was not previously addressed.

The automation control systems are shown in Figure 2.5 could be an ‘Automation gas lift’ These are still in use in some plants for oil production. The model is based on automation with unstable production from gas lift wells. Field facilities such as well head, casing pressure, and tubing pressure were connected with an automation controller in order to get more oil production and smooth wells behavior during production start-up and shut down. (Field experience and simulations demonstrated that more oil can be produced with automatic controls which were applied for stabilization to enhance oil production and many other benefits that the difficulties highlighted by [24] were understanding the day-to-day production variance before automation control was connected in Amberjack oil field in the Gulf of Mexico). (Amberjack field was a trial for production engineers and offshore workers spent large amounts of time just gathering the required well and facilities information to sympathetic in dividable well performance and field supervision was very challenging). The gas lift automation system was to the daily struggle of collecting enough information needed and assisted to develop, monitor the well data and control individually well gas-lift rate in real time from engineer’s laptop computer).

Therefore, by utilizing automation control what before require four or more days of analysis can be complete in real time on a laptop from dial-up or network collection.

The results showed that using new automation control for older mature oil field can be a hard task to defend. In Amberjack field \$ 860,000 was spent to install and commission the surface gas lift control system. This spending was financially acceptable based on anticipated production rise of 600 BOPD from gas-lift wells and additional improvement of oil and enhanced the well performance with real-time data that is necessary for field process and management. A classic automated well head armed with temperature, pressure, pressure switch, flow transmitters and valve control. All of these facilities

equipment must be link correctly in order to maximize the potential of the optimisation system as can be seen in Figure 2.5. The previous work that was described above was conducted at the surface facility, however, in work, the control of the injection rate from the down hole that will eventually lead to improvement of the well performance and reduce the operational cost.

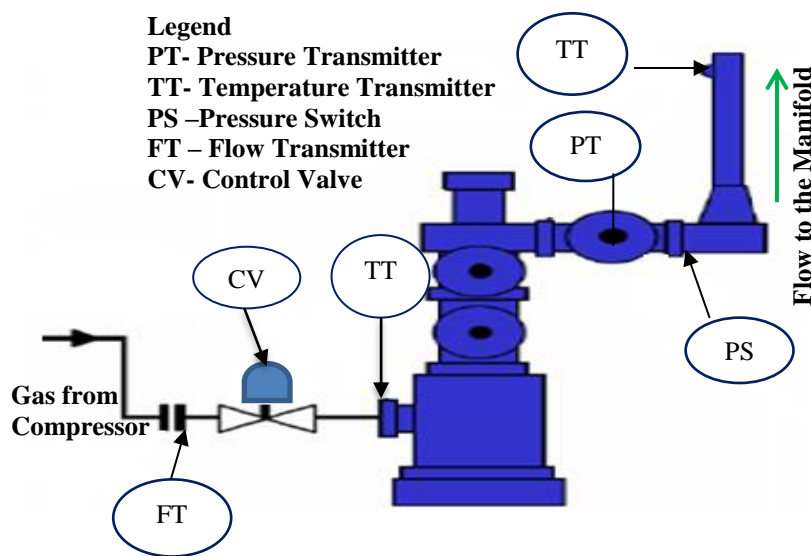


Figure 2.5: Individual Well Head Schematic

Smart field was also summarized by Berg, in which the Shell was implemented with smart field's concepts to improve oil production and raise recovery. (He reported that the rate is reached only if the solution applied to cover the three elements; process and people namely technology and add automation wells can only built in at the start of a project on average, the following estimates are used 8% ultimate recovery increase, 10% rise production, reduced development danger and uncertainty and additional important benefits include

improved HSE. The automation field concepts grew out of the thinking that showed the development and achievement of smart wells. Figure 2.6 explains the essence of smart field vision [25].



Figure 2.6: Automation Fields Value Loop Concept [25]

The gas lift optimisation is becoming more important now a day in the petroleum industry. A proper lift optimisation can reduce the operating cost, increase the net present value (NPV) and maximize the recovery from the asset. A widely accepted definition of gas lift optimization is to obtain the maximum output under specified operating conditions. In addition, gas lift, a costly and indispensable means to recover oil from high depth reservoir entails solving the gas lift optimization problems. Gas lift optimisation is a continuous process; there are two levels of production optimization. The total field optimisation involves optimizing the surface facilities and the injection rate that can be achieved by standard tools software. Well level optimisation can be achieved by optimising the well

parameters such as point of injection, injection rate, and injection pressure [26]. In the present work, these parameters will also be examined.

Kanu, *et al.* presented the formulation of an economic slope based on the concept that the profit from an incremental recovery of oil should be equal to the cost of additional gas injected to effect that production. This economic slope was used to give a total amount of gas at the ideal economic point for an individual of wells and also he showed that the application of systems analysis techniques to gas lift design improved production from gas lifted wells by at least 50%. However, by utilizing smart valve with real time opening and close that will lead to enhance the well performance[27].

Two methods were presented by J.L. McAHan, [28] to find the ideal distribution of the obtainable lift-gas for a group of wells on a platform. In one method they applied a linear programming technique to the polynomials representing the well performance curves. They also used a step-by-step method, where the well performance curves were scanned to find the curve with the maximum slope after all the wells had been kicked off with enough gas. The gas lift rate to the corresponding well was then increased by one step and so on until all the available gas was distributed. Total oil rate for both methods was almost the same. Although gas allocations to individual wells varied. They suggested that the step-by-step method was more appropriate to be incorporated in an automatic gas lift optimization system with computer control of gas lift chokes. In this research, the economic study will be presented.

Optimization of a continuous flow gas-lift system was carried out by X. Zheng, He reported that by maximizing the daily cash income from the productions of the gas lifted wells subject to various system constraints such as imperfect total liquid production rate, restricted total gas production rate, limited separate well liquid production rates and

limited lift-gas supply [29]. In this work, control of the gas injection rate carried out at the sub-surface facilities, However, by using the smart gas lift the gas injection can be controlled at any time which will lead to an increase in production rate and improvement improving daily cash income.

Xu and *et al.* reported that changes in the gas rate at the surface cause dynamic changes in the well starting at the bottom- hole and working their way up to the surface. Since the typical oil reservoir can be more than a mile below the wellhead, many subsequent and sequential upsets can be induced before the previous ones reach the surface [30].

In this investigation, the economics of using the smart gas lift will be evaluated and considered within the boundaries of the operating conditions. Also, gas lift valves, considered to be the heart of the gas lift system, will describe the effects on injection gas pressure on well head pressure and gas lift operation conditions, (see also, Chapter-4).

2.4 Gas lift Injection Quality

Gas hydrates are ice-like non-stoichiometric crystalline compounds. These are cages of water molecules, formed around guest molecules, which are simply called hydrates in gas and oil industries.

2.4.1 Treatment of Gas

Natural gas produced from gas wells or associated gas may contain impurities such as acid gases H_2S , CO_2 , and other impurities. These two gases in particular become very corrosive in the presence of water or water moisture. These acid gases can cause a lot of corrosion problems in producing wells, injection wells, and transporting and processing facilities. Therefore it is vital to remove these two acid gases from gas stream in order to eliminate corrosion problems and meet sales gas specification standards.

2.4.2 Methods of removing H₂S and CO₂ from the gas stream

They can be classified depending on their chemical reaction, absorption, adsorption or permeation:

- 1.** Chemical solvent process using Aqueous Alkanol Amine such as DEA.
- 2.** Physical solvent process such as Fluor solvent and selexol.
- 3.** Adsorption using molecular sieve.
- 4.** Physical separation cryogenic “low temperature” distillation.
- 5.** Membrane separation process.
- 6.** Biological processes [31].

2.4.3 Dehydration Unit

Dehydration of natural gas is a process of removing water from the natural gas in order to prevent gas hydrate formation, corrosion, high pressure drop, and slugging in the processing and transportation facilities .

Glycol dehydration is one of the most common methods of gas dehydration used in the oil industry. An absorption tower either packed or tray is used in which lean glycol and wet gas come into contact as they pass counter current in the tower. Dry gas leaves at the top of the tower while rich glycol leaves at the bottom of the tower. The rich glycol then passes to the reboiler where water is removed and lean glycol is reused in the process. Chemical additives can be used to overcome operational problems such as corrosion and foaming. Figure 2.7 illustrates Typical Flow Diagram of Glycol Dehydration Unit.

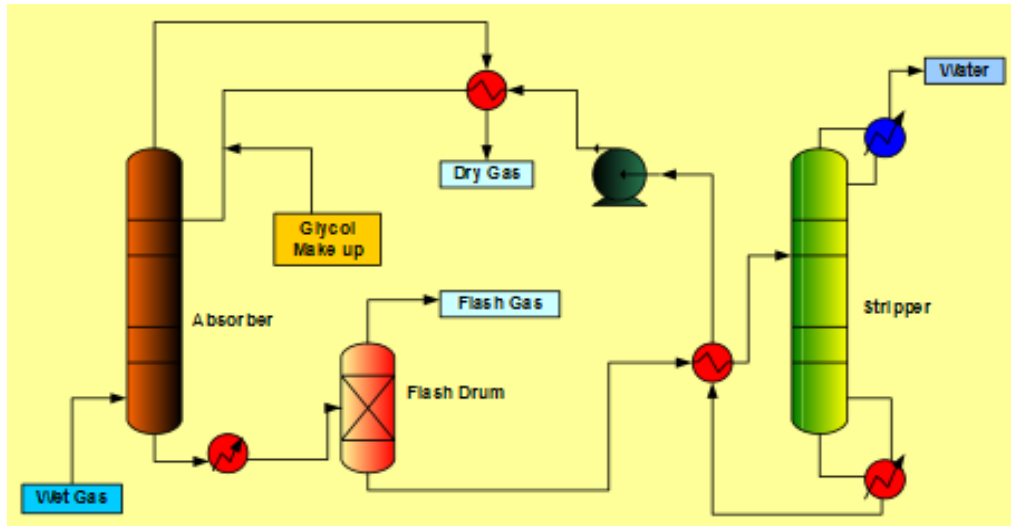


Figure 2.7: Typical Flow Diagram of Glycol Dehydration Unit[31]

2.5 Theory and Concept in Gas Lift Optimisation

For production optimisation and gas lift investigating of different wells, it is truly necessary to have conceptions of the inflow and outflow performances of wells. In the following sections, relevant theories and concepts have been outlined.

i. Production system performance

The production system performance (well and reservoir deliverability or productivity) is a function of the pressure difference, it is dependent on:

- Inflow Performance
- Completion Performance
- Vertical Lift Performance
- Surface piping network
- Surface Facilities (separator pressure)

ii. Inflow Performance Relationship (IPR)

The inflow performance relationships IPR it a relationship between a Bottom hole pressure and well flow rate the IPR curve is a function of the following parameters:

- Inflow
- Reservoir pressure
- Pay zone thickness and permeability
- Reservoir boundary type and distance

- Wellbore radius
- Reservoir fluid properties
- Near-wellbore condition
- Reservoir's relative permeability.

The ability of a well to lift up fluid signifies its inflow performance. Inflow performance of a well with the flowing well pressure above the bubble point pressure can be stated by Darcy's equation for a single well located in the centre of a drainage area, produces steady state condition. Darcy's equation [32].

$$Q = \frac{2\pi KH}{\mu B} \frac{(P_e - P_{wf})}{\ln(r_e - r_w) + S} \quad 2.1$$

Where:

Q= Production rate, bbl/day, K = Well permeability, Darcy, H = Formation thickness, ft.

P_e = Reservoir pressure, psi P_{wf} = flowing well pressure, psi

μ = fluid viscosity, cp

S = Skin factor.

iii. Productivity Index (PI)

The reverse of the slope of the IPR curve is called productivity index (PI or J), PI represents the ability of the well to give up fluids, and the inflow performance types are illustrated as followings:

PI is one of the important characteristics of a well's inflow performance. It depends on the reservoir and fluid properties.

$$PI = \frac{q}{(P_e - P_w)} = \frac{2\pi kh}{\mu B} \frac{1}{\ln(r_e - r_w) + S}$$

2.2

If the PI is known, evaluation of the expected inflow rate under specified flowing well pressure is straightforward:

The relation between the production rate and the drawdown pressure is called Inflow Performance Ratio or IPR curve. Production rates at various drawdown pressures are used to construct the IPR curve. It reflects the ability of the reservoir to deliver fluid to the well bore.

iv. IPR curve for one phase (straight line IPR)

In case of a single phase flow, the relation between the production rate and the pressure drop is a straight line. As follows from the Figure 2.7 the slope of the IPR is inversely proportional to the PI value; i.e. $\text{Slope} = 1/\text{PI} = \text{Constant}$.

This assumption is valid only in case of under saturated reservoirs (reservoir pressure above bubble point pressure), or reservoirs with very low bubble point pressure or low very gas oil ratio (GOR). This is mostly the case for strong water drive reservoir where the pressure remains above the bubble point pressure. The IPR curve is a straight line for this case as shown in Figure 2.7.

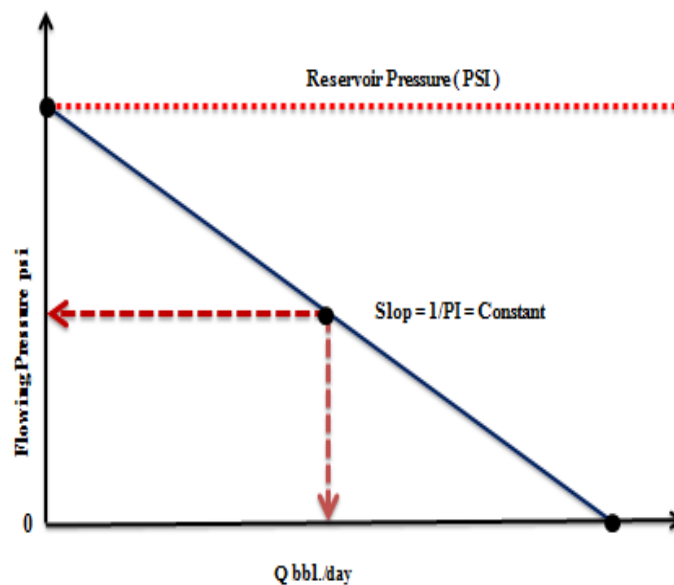


Figure 2.8: IPR Curve for Single Phase (Liquid) Flow

The PI for this case is represented using the following equation:

$$PI = \frac{Q}{(P_r - P_{wf})} = \text{bbl/day/psi}$$

2.3

Where:

Q: liquid flow rate, bbl/day

P_r : Average reservoir pressure, psi

P_{wf} : bottom-hole pressure, psi

This case is used to represent one phase fluid flowing through the reservoir, liquid phase.

If the flowing well pressures p_{wf} is below the bubble point pressure P_b . At this condition ($p_{wf} \leq P_b$), the IPR is no longer a straight line. It has been illustrated in Phase diagram Figure.2.8 which states that at such bottom hole conditions, a two phase flow occurs in a reservoir where both oil and gas flow together towards the well. This type of flow is called solution gas drive.

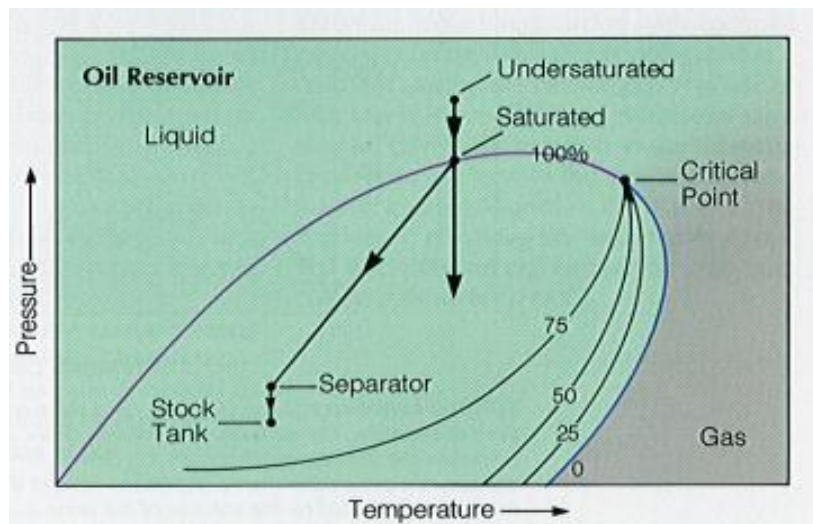


Figure 2.9: Phase Diagram for Two Phase Flow [33]

A two-phase flow has the effect on the IPR curve. It deviates from a straight line resulting in reduced values of the productivity index corresponding to reduced values of the flowing well pressure.

v. Vogel's Correlation

As the pressure in a reservoir declines from depletion, the producing capacity of the wells will decline. The decline is caused by both a decrease in the reservoir's ability to supply fluid to the wellbore and, in some cases, an increase in the pressure required to lift the fluids to the surface. That is, both inflow and outflow conditions may change. The only way in which the inflow can be kept high, once the well has been stimulated to reduce reservoir pressure drop to a minimum, is by pressure maintenance or secondary recovery. This will eventually be initiated in most oil reservoirs, but methods are available to reduce the flowing wellbore pressure by artificial means, that is, to modify the outflow performance of the well. All the methods presented earlier for generating IPRs, apply equally well to either flowing or artificial lift wells. The reservoir inflow performance depends on P_{wf} and is completely independent of what methods are employed to obtain a particular value of P_{wf} .

Therefore, no new procedures are required for reservoir performance in analyzing artificial lift wells. The Inflow Performance Relationship (IPR) describes the behavior of the well's flowing pressure and production rate, which is an important tool in understanding the reservoir/well behavior and quantifying the production rate. The IPR is often required for designing well gas lift rate, optimizing well production, nodal analysis calculations, and designing artificial lift. Different IPR correlations exist today in the petroleum industry with the most commonly used models are that of Vogel's. Vogel's correlation gave a good match with the actual well inflow performance at early stages of production but deviates at later stages of the reservoir life. Therefore, this will affect the prediction of inflow

performance curves in case of solution gas drive reservoirs, because at later stages of production the amount of the free gas that comes out of the oil will be greater than the amount at the early stages of production [34].

The productivity of an oil well draining a solution-gas drive reservoir was investigated by Vogel using numerical simulation. Vogel used a computer model to generate IPR (Inflow Performance Relationship) for a total of 21 simulations covering a wide range of oil, PVT properties, and relative permeability's were made. It appeared that if several solution-gas drive reservoirs were examined with the aid of this program, empirical relationships might be established that would apply to solution-gas drives reservoirs in general.

Vogel normalized the calculated IPR and expressed the relationships in a dimensionless form

$$\frac{P_{wf}}{P_r} = \text{Pressure dimensionless}$$

$$\frac{Q}{Q_{max}} = \text{Flow rate dimensionless}$$

By using dimensionless pressures and rates, Vogel found well productivity could be described by equation 2.4

$$\frac{Q}{Q_m} = 1 - 0.2 \frac{P_{wf}}{P_r} - 0.8 \left(\frac{P_{wf}}{P_r} \right)^2$$

Where q is oil production rate in bpd, q max is maximum oil production rate in bpd, pwf is bottom-hole flowing pressure in psia, and Pr is average reservoir pressure in psia. Eq. (2.4), called Vogel's Inflow Performance Relation (IPR), was found to describe simulated well productivity with a typical accuracy of 10%. Errors as high as 20% were noted for simulations of viscous crudes and/or damaged wells with skin factors great than +5. Over the last quarter century, Vogel's IPR curve has been extensively used to predict oil well performance. Because of his success, the question arose as to whether Vogel's IPR could also describe gas and water production from oil well. It is important that Vogel's equation

gives the best fit for the results of well testing and simulation runs. Plotting these results on dimensionless form gives almost the same curve in all cases, as illustrated in Figure 2.9 [35]. In this research, Vogel correlation has been used to validate the experimental results and will be shown in Chapter 4.

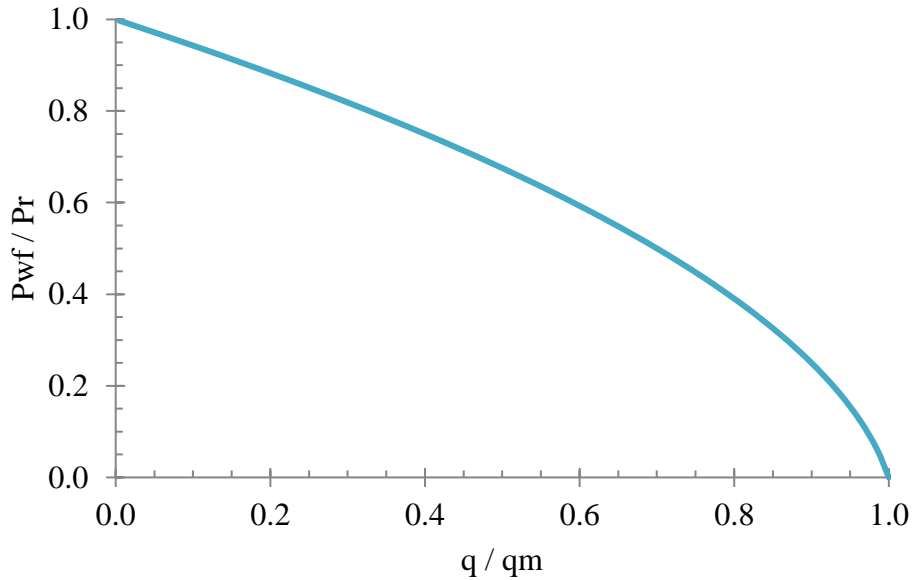


Figure 2.10: Inflow performance under a solution gas drive

The production rate and the bottom-hole pressure will gradually decrease in the whole flowing production process. The decrease in flowing bottom-hole pressure will lead to the increase in producing the gas-oil ratio, which will first rapidly increase on the basis of the lower initial value and then gradually decrease to a point lower than the initial point. Thus, the problem of prolonging the flowing period of the oil well changes into the problem of rationally utilizing gas expansion energy [36].

Summary

- This chapter concentrates mainly on the essential review of past research studies which lead to further justification in carrying out this research. The benefits and reasons why smart gas lift is necessary are also not left out. Furthermore, this

chapter covers an extensive literature survey of an overview of previous work regarding gas lift optimization.

- In traditional gas lift valve, the injection gas volume is usually controlled by one (or more) orifices in the valve, and by the movement of the ball and stem. The selection of the correct orifice size is usually carried out with the help of charts supplied by the manufacturer. It can, therefore, be seen that the gas passage of this valve will be significantly affected by the bellow movement and pressure inside the valve. The gas lift design engineer must verify that the valve selected can pass the required amount of gas at the given down hole design conditions, otherwise, the well will not unload.
- The goal of real-time gas lift valve, analysis, and optimization is to have a real-time that will, at any point in time, provide the engineer with an understanding of how the gas lift valves are performing. This will empower them to make the adjustments necessary to ensure that the well is stable and injecting into the orifice.
- Monitoring and adjusting injection and production systems maximize recovery. Appropriately stable injection and production capacities can maintain reservoir pressure and sweep efficiency. Gathering injection rate and pressure data determines and tracks infectivity. Gas injection rate effect in the well head and the well productivity will be given in Chapter- 4.
- This chapter also includes a literature review of the Vogel IPR for solution gas-drive systems. Vogel used a computer model to generate IPR (Inflow Performance Relationship) for a total of 21 simulations covering a wide range of oil, PVT properties, and relative permeability's were made. It appeared that if several solution-gas "drive reservoirs were examined with the aid of this program, empirical relationships might be established that would apply to solution-gas drives reservoirs in general.as mentioned in this Chapter. In this research, Vogel correlation has been used to validate the experimental results and will be shown in Chapter 4.

CHAPTER 3

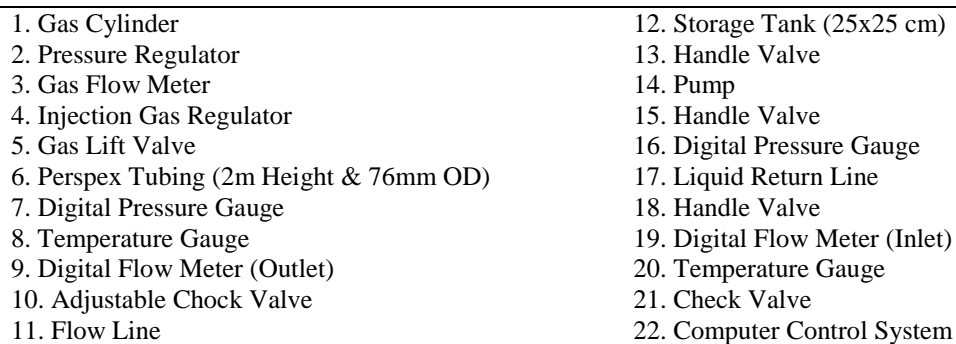
EXPERIMENTAL APPARATUS AND METHOD OF DATA PROCESSING

3.1 Introduction

This chapter generally presents detailed information on the experimental apparatus, test procedures and the method of data collection. This Chapter also discusses the experimental errors which have an effect on the results and all the operating assumptions that have been considered throughout this work. The chapter also presents a devoted computer program LabVIEW which was used in the determination of the gas passage through the Smart Gas Lift valve (SGL) for the real-time data collection.

As discussed previously in Chapter-1, the aims and objectives of this study are to develop of remotely controlled Smart Gas Lift Valve unit which can be connected to the control line to provide a real-time data collection to the surface. This novel method can be replaced with the current conventional injection pressure operating the valve. In this research, smart gas lift valve was used to allow the port size of the gas lift valve to be remotely adjusted from the surface by a computer program which controls the gas passage through the valve. Furthermore, obtaining the optimum gas injection rate is important as an excessive gas injection can decline the production rate and consequently, increases the operation cost.

Figure 3.1 demonstrates the schematic diagram of the experimental setup which shows the major experimental components used in this investigation.



The major components of the above diagram are describing below.

3.1.2 Gas Cylinder, Pressure Regulator, and Gas Flow Meter

Utilization of the gas energy is accomplished by the continuous injection of a controlled stream of gas into the liquid column to provide the lifting energy. In this study, a gas cylinder (or a compressor) used to provide air as an injection media and the injection pressure and flow rate controlled by a pressure regulator and manometer.

3.1.3 Automation Gas Lift Valve

The gas lift valve is a motorized control valve designed to control the flow of air to inside the transplant tube. A DC motor controls the opening width to regulate the flow. A potentiometer is integrated into the electrical actuator to capture the position. A microcontroller enables digital control. Two buttons are provided for manual control. The set point is displayed in % from 0-100%.The valve was connected with a control line to provide real opening or closing and can be operated with a variable opening flow proportional rate through the use of a computer program. The air flow rate that fed into the tubing can be controlled at a different flow rate and different injection pressure by using air, an injection regulator and air flow meter. A control valve is a power operated a device capable of modulating the flow at varying degrees between minimal flow and full capacity in response to a signal from the computer program. A control valve is capable of changing the position of the flow controlling element in the valve. The valve modulates flow through movement of a valve plug in relation to the port(s) located within the valve body.

The valve plug is attached to a valve stem, which, in turn, is connected to the actuator. The actuator is electrically operated, directs the movement of the stem as dictated by the external control device. Figure 3.2 shows the Smart Gas Lift Valve and the injection point where the valve was connected and Figure 3.3 shows the experimental loop control system. As described earlier, the aim of this investigation is to control the injection port size remotely from the top surface. In this study, the valve port size varies from 4% to 100%.

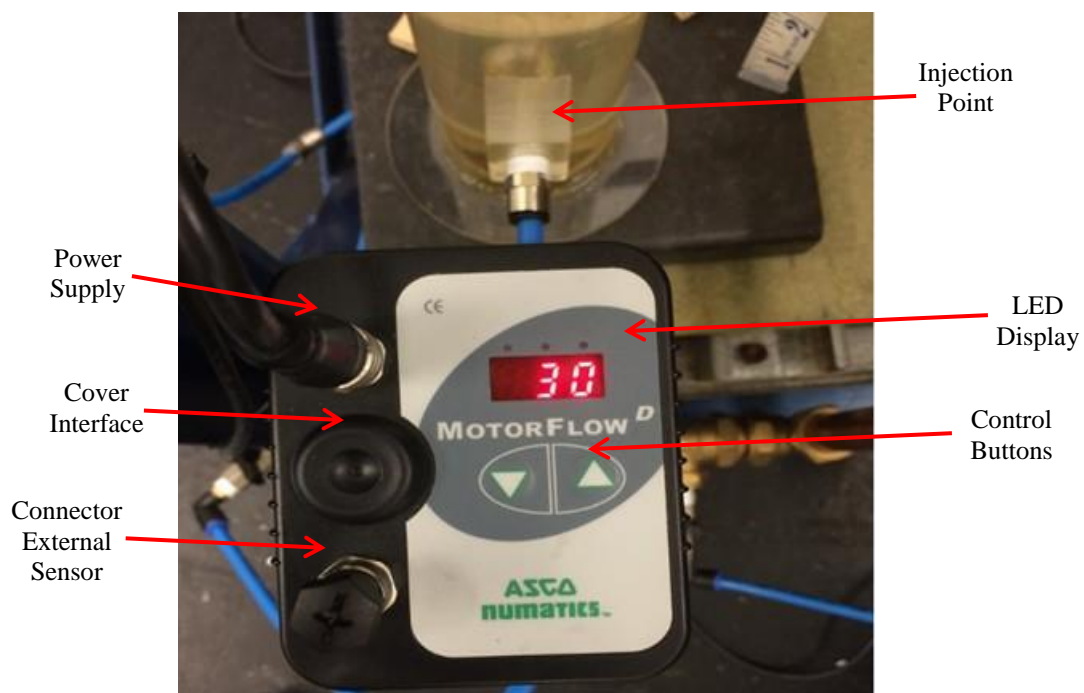


Figure 3.2: Automation Gas Lift Valve

The Smart Gas Lift Valve consists of the following features:

- Flexible valve opening (flow), proportional to the switch signal
- Digital controller with two functioning buttons and position sign
- Valves do not need a minimum working pressure
- Little power consumption
- Wear-resistant ceramic control discs

- Insensitive to contamination
- Suitable for vacuum and overpressure applications
- Mechanical separation of electrical actuator from fluid-carrying parts
- Valve position maintained on loss of power
- Valves can be mounted at any point

The technical characteristics of the Smart Gas Lift Valve are as follow:

- Orifice size: 15mm
- Flow coefficient: (3.5 m³/h, 58 l/min)
- Electrical characteristics
- Set point 0-10V; 0/4-20mA
- Feedback 0-10V; 0/4-20mA
- Supply Voltage 24VDC \pm 10%
- Power Rating Max: 10W
- Actuating time: 2 sec
- Operating conditions
- Ambient temperature: 0...+50 °C
- Operating pressure maximum: 10 psi
- Storage temperature: -20...+70°C
- Differential pressure: -0, 9 to +10 bars
- Ambient temperature range: 0°C to +50°C
- Full viscosity: 80 (mm²/s)
- Actuating time: 2 s

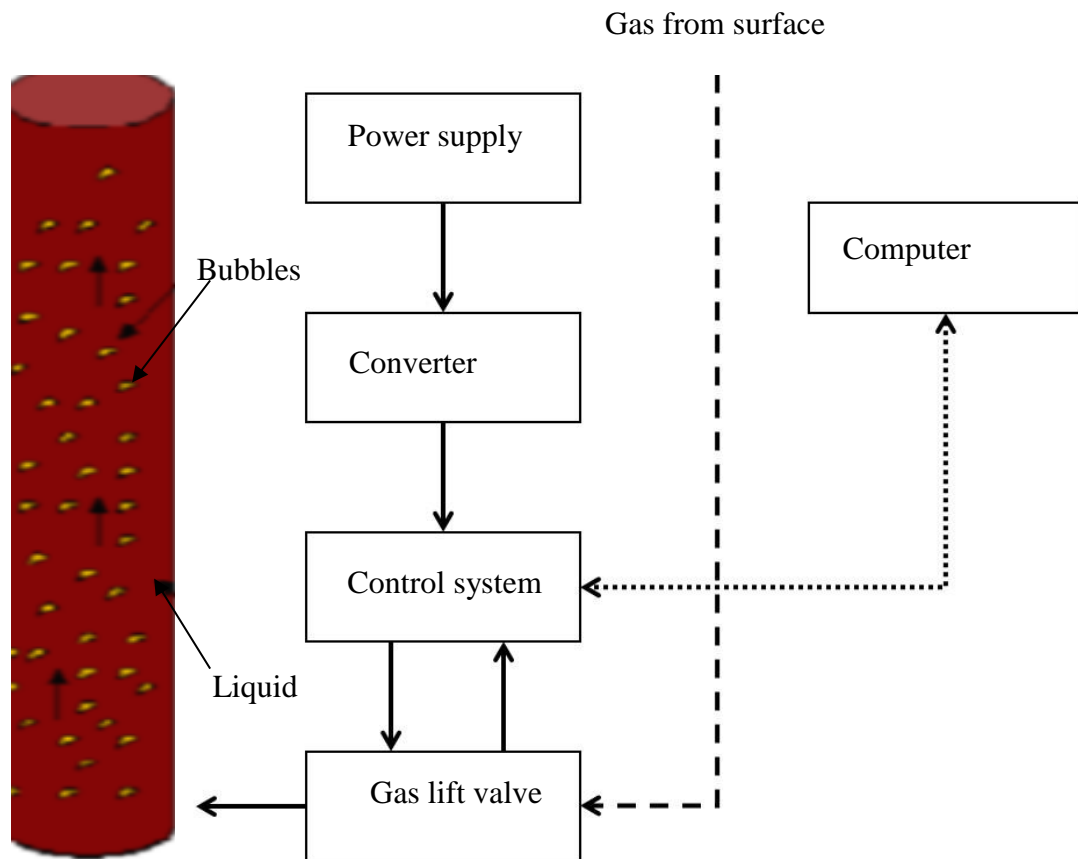


Figure 3.3: Gas Lift Control System

A DC motor controls the opening port size to maintain the injection pressure and flow rate of the air into the system. A potentiometer is integrated into the electrical actuator to capture the opening position. A control valve is a power operated a device capable of modulating the flow at varying degrees between minimal flow and full capacity in response to a signal from the computer program. A control valve is capable of changing the position of the flow controlling element in the valve. The valve modulates flow

through movement of a valve plug in relation to the port(s) located within the valve body. The valve plug is attached to a valve stem, which, in turn, is connected to the actuator. The actuator is electrically operated, directs the movement of the stem as dictated by the external control device. Figure 3.3 shows the experimental loop control system.

Practical electronic converters use switching techniques. Switched-mode DC-to-DC converters convert one DC voltage level to another, which may be higher or lower, by storing the input energy temporarily and then releasing that energy to the output at a different voltage. The power converter that was used in the experiment to provide the constant voltage to the smart gas lift valve which has the following features:

Input AC voltage range: AC 100 – 240 V

- AC Input Frequency: 47 – 63 Hz
- Productivity: $\leq 78\%$
- Power factor: ≤ 0.9

Constant voltage and current range selection:

- (16 V/ 5A) selection I
- (27.6 V/3A) selection II
- (0 – 36 V/ 2.2 A selection III
- Characteristics: load regulation (0-100%)
- Line regulation $\pm 10\%$
- Dimensions: $53.5 \times 127 \times 330$ mm ($2 \times 5 \times 13$ inch).

Figure 3.4 illustrates the power converter that was used in the experiment to provide the constant voltage to the smart gas lift valve.

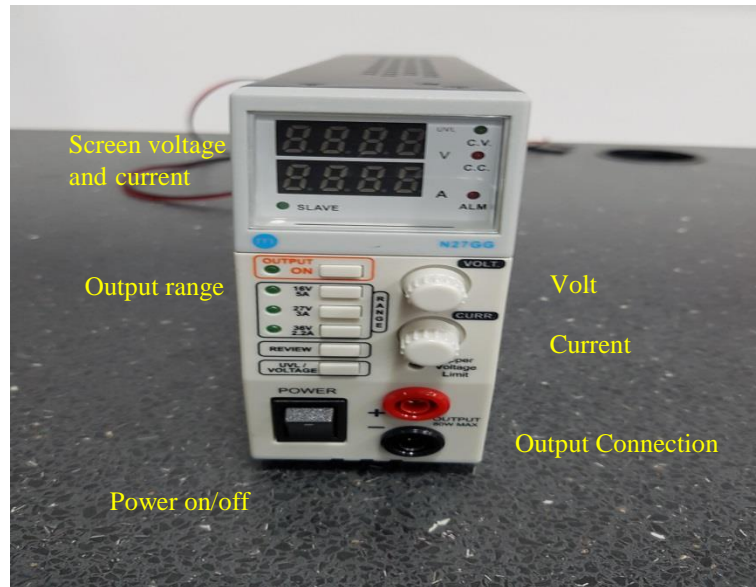


Figure 3.4: Power Converter

Figure 3.5 illustrates the control loop which was used to control the smart gas lift operation. The control consists of a controller, a final control element process, and the sensor. This controller was connected with the computer program by utilizing USB connection.

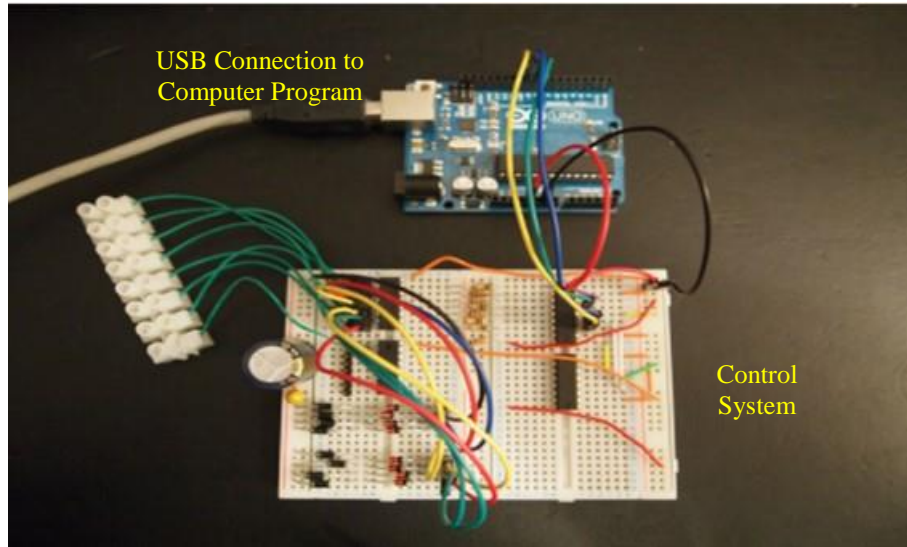


Figure 3.5: Experimental Control Loop

3.1.4 Perspex Tubing (2m Height & 76mm OD)

In an oil field, the production tubing includes several pipelines linked together in order to achieve the reservoir and reach the production target. The design of this tubing, mainly, depends on the reservoir geometric configurations. In this experimental study, the production well tube simulated by using a 2 m PVC tube to have better visualization and see the flow regimes and fluctuations at different locations can be visually detected.

3.1.5 Pressure Gauges (Inlet and Outlet)

As can be seen in Figure 3.1, there are two pressure gauges installed in this experimental work as indicated #7 and #16. The first gauge is to measure the pressure of the flow coming out of the well tube (which is called pressure head) and the second gauge is located after the pump to measure the inlet flow going to the system which is simulating the reservoir pressure.

The features and accuracy of these digital pressure gauges are describing in Table 3.1.

Table 3.1: Features and Accuracy of the Digital Pressure Gauge

Features: <ul style="list-style-type: none">• Small and compact dimension• High reliability and durability• Installation flexibility: vertical or horizontal• Wide rated voltage: 2.4 to 26 VDC• Digital output, open collector type	Accuracy: The water digital flow meter has an accuracy of +/- 5% and repeatability of +/- 1% and the accuracy of pressure gauges were +/- 1.6 %.
--	---

3.1.6 Digital Temperature Gauge

The oil coming from the reservoir has normally high temperature (about 240°C). Therefore, this experimental setup consists of two digital temperature gauges to monitor any changes from the reservoir to the top surface (see #8 and #20 in Figure 3.1). The first temperature gauge has been located after the pump to show the reservoir temperature and the second one installed at the top of the PVC tube to monitor the flow temperature in the top surface.

3.1.7 Digital Flow Meter (Outlet)

In this study, two different well reservoirs have been considered: (i) Natural Flow Well, in which the fluid flow rate is almost constant from the reservoir up to the top surface. This is due to having high pressure of the reservoir. (ii) Gas Lift Well, in which the reservoir pressure is not enough to push the fluid coming out of the production tubing which means the outlet flow is almost zero. Therefore, an external energy needs to be applied to assist the production. In this experimental setup, the first digital flow meter installed after the pump to record the reservoir flow rate (see #19 in Figure 3.1) and the second digital flow meter located at the top to presents the flow rate coming out of the production tubing (see #9 in Figure 3.1).

3.1.8 Storage Tank (25x25 cm)

The petroleum reservoir is a subsurface pool of hydrocarbons contained in permeable or cracked rock formations. The naturally occurring hydrocarbons, such as crude oil or natural gas, are surrounded by overlying rock formations with lower permeability. In this experiment, a 25x25 cm plastic storage tank is used to simulate an oil reservoir.

3.1.9 Pump (Reservoir Pressure)

An adjustable speed pump system (see Figure 3.6) used to stimulate the real reservoir pressure. The well endpoint (down-hole) is linked to the pump and is controlled to produce proper pressure (referred to as reservoir pressure) at the discharge of the pump system.

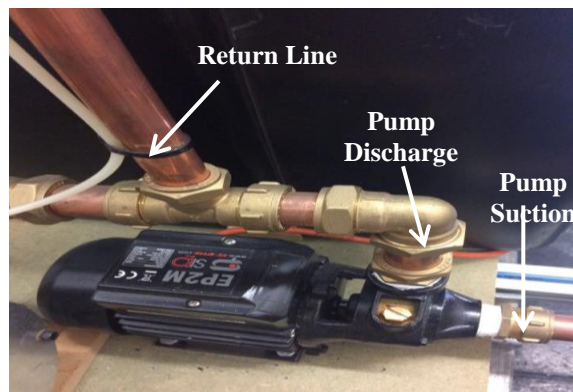


Figure 3.6: Pump to Stimulate the Reservoir Pressure

There is also a manual valve downstream of the pump system that is utilized to match the difference in pressure between the reservoir and the down-hole pressure. The discharge pump system is measured by a flowmeter.

Table 3.2 shows the pump technical specification.

Table 3.2: The Pump Technical Specification			
Power Input	550 w	Max. flow rate	40 l/min
Power Output	370 w	Outlet	1'' (bsp)
Max. Pump Head	40 m	Voltage.	230v -50HZ
Max. Suction	6 m		

3.1.10 Check Valve

The prime function of a check valve is to protect mechanical equipment in a piping system by preventing reversal of flow by the fluid. This is particularly important in the case of a pump, where backflow could damage the internals of the equipment and cause an unnecessary shutdown of the system

3.1.11 Computer Program

Smart completion technology is permitting engineers to enhance production or injection programs, develop reservoir performance, reach higher extraction ratios, and decrease field growth and interference charges. The technologies dependability has been established in high-productivity wells are appropriate for- determining smart completions that are today being connected in wells with lower efficiency to assist in safeguarding against reservoir uncertainties and deliver incremental production. Furthermore, to control the injection of air with lift valve a computer program was connected to the valve with databases. The gas lift valve was opened at different percentages with a range from 0 – 100.

A devoted computer program LabVIEW was also used in the determination of the gas passage through the smart gas lift valve, thus distilling the real-time data. Figure 3.7 shows the Simulation palette in LabVIEW. Figure 3.7 illustrates The Simulation Palette in LabVIEW. LabVIEW is Laboratory Virtual Instrumentation Engineering Workbench. It is

a platform that lets interface a computer with an experiment. LabVIEW programs are called virtual instruments or VIs because their appearance and operation imitate physical instruments. The LabVIEW contains a comprehensive set of tools for acquiring, analyzing, displaying and storing data, as well as tools to help you troubleshoot code you write. In LabVIEW, you build a user interface, or front panel, with controls and indicators. Controls are knobs, push buttons, dials, and other input mechanisms. Also, with LabVIEW Control Design and Simulation Module can construct plant and control models using transfer function, state space, or zero-pole-gain. Analyses system performance with tools such as step response, pole-zero maps, and Bode plots. Simulate linear, nonlinear, and discrete systems with a wide option of solvers [37].

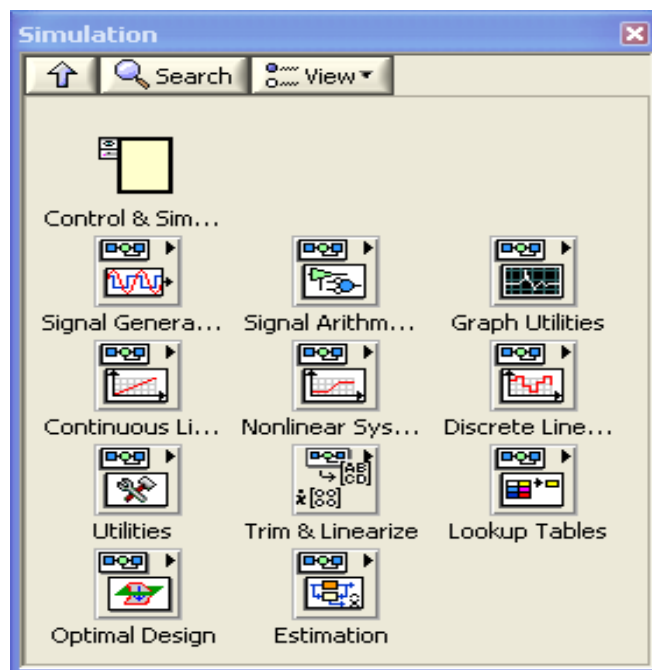


Figure 3.7: The Simulation Palette in LabVIEW

3.2 Experimental Set-Up

Figure 3.8 illustrates the laboratory connection characterizes a gas lift well, utilizing compressor air as a source of gas media (8) and, a 25x25 cm plastic storage tank is used to simulate the reservoir filled with water as production fluid (1). The production tube is PVC so too, facilitates visual review of the flow regimes and fluctuations at different levels that can be visually observed (6). The length of the tube is two meters in height and with an inner diameter of 66 mm; outlet diameter of 76 mm, pipe thickness of 5 mm. A compressed air was used as lift gas and water as the produced fluid. A pump (3) is used to deliver high-pressure water from a plastic tank to a certain level into the transparent tube. The pump can be operated with a variable speed to produce an appropriate pressure (mentioned to as reservoir pressure) and also, can be controlled by using a manual valve in the discharge of the pump. When the pump pressure could not deliver the fluid to the surface, a gas lift technique was applied by injecting air into the tubing by using an electric valve (14) which was connected at the bottom of the transparent pipe to allow the air to flow into the tubing. The valve was connected with a control line to provide real opening or closing and can be operated with a variable opening flow proportional rate through the use of a computer program (13) and the air flow rate that fed into the tubing can be controlled at a different flow rate and different injection pressure by using air an injection regulator (7) and air flow meter (9). As soon as the air is injected into the tubing it reduces the fluid hydrostatic pressure and the density of the production fluid and delivers the fluid out of the tubing. Inflow and outflow were measured by using two digital flow meters; pressure gauges were installed to monitor the inlet and outlet pressure (12) also return line (4) was installed to control inlet flow rate and the digital temperature gauge was connected to observe the system temperature (10).

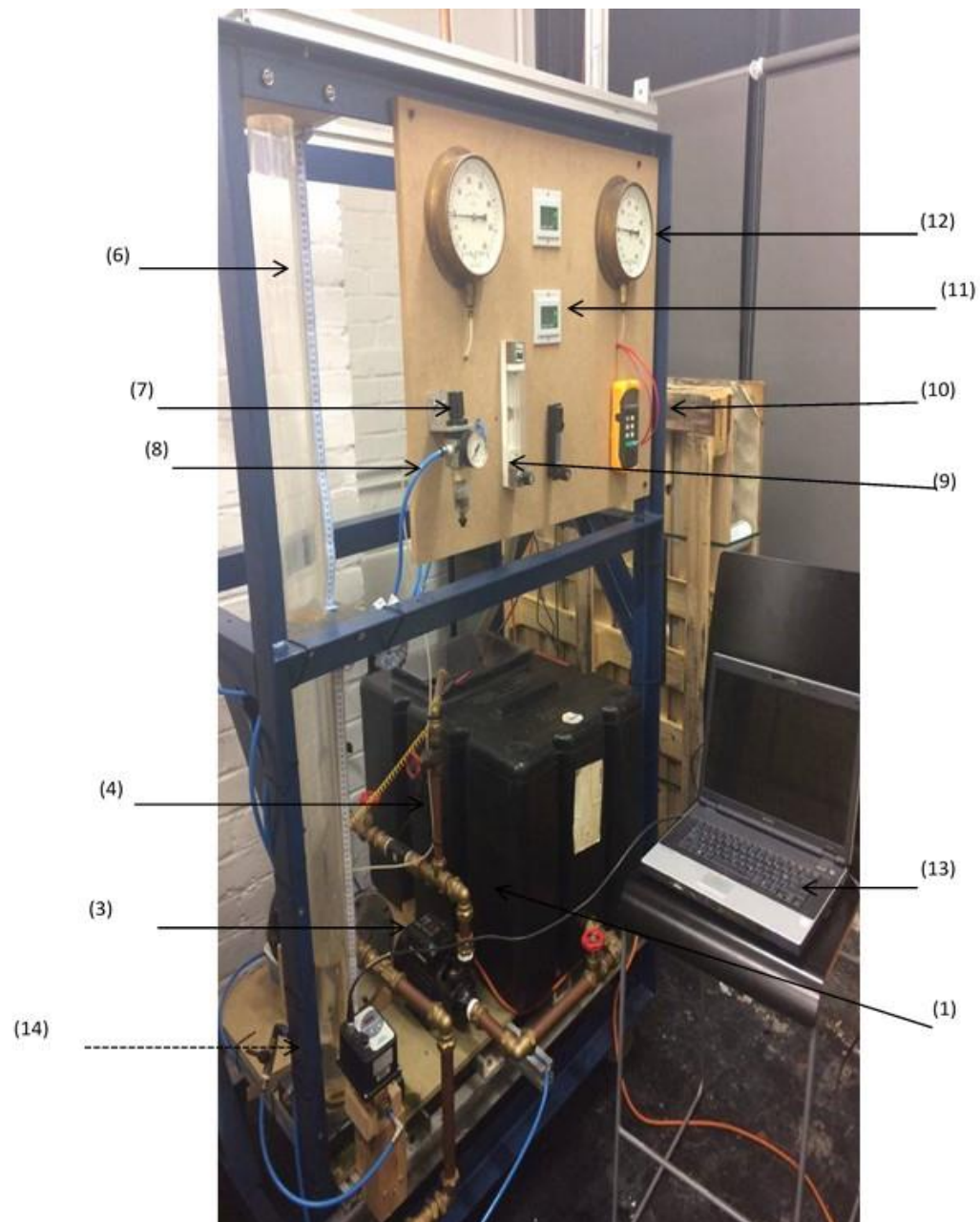


Figure 3.8: Experimental Set up

3.2.1 Risk Assessment

- i. A risk assessment form was completed before the experiment carried out and personal protection equipment such as hat, safety footwear, overall and eye protection was worn
- ii. The strength of the test frame under the designed loading, including its overall robustness and stability were tested.
- iii. The measurements were taken to ensure that the designed for the maximum load in the system is capable of applying.
- iv. Emergency instructions were clearly displayed in case of an emergency. These include: How to shut down the experimental safely, the location of emergency stop button and contact an emergency number.

3.2.2 Construction of the Experimental Setup

Connect the storage tank with the pump suction.

- ii. Install hand valves at the tank and at the bottom and top of the rig.
- iii. Install the return line from the discharge pump to the tank to control the pump discharge rate.
- iv. Connect the pump to the bottom of the transparent pipe.
- v. Install the measurement gauges (i.e. Pressure gauges, Temperature Gauges and Flow Meters) at the bottom and the top of the production string pipe to determine the inflow and outflow rate.
- vi. Install the pressure gauges at the pump suction and at the top of the rig.
- vii. Connect the flow line from the well head to the storage tank.
- viii. Make a hole with the size of the bottom of production pipe to utilize it as injection point
- ix. Connect the smart gas lift valve at the injection point
- x. Connect the smart valve with controller system

- xi. Connect the controller system with the computer program
- xii. Connect the valve to electricity.

3.2.3 Measurement and Control Variables

There are numbers of potentials to regulate the entire system operation, such as:

- i. Measurement and control the air injection volume to determine the optimum injection rate.
- ii. Control and record the air injection pressure to obtain the optimum injection enter to the system.
- iii. Record and observation the well head pressure is required to study the effect of injection rate pressure and volume on the well operation
- iv. Record the inlet and outlet pressure of the system
- v. Record the inlet and outlet flow rate to determine the efficiency of the gas injection operation.
- vi. Operate the smart gas lift valve with different port size to study the effect of increasing or decreasing the port size on the production performance
- vii. Analysis and evaluate the results.
- viii. Adjustment of the pump speed so as to emulate different reservoir pressure situations
- ix. Adjustment of the liquid feeding valve so as to affect the (well) down-hole pressure and water inflow.
- x. Regulation of the gas injection valve so as to affect the gas injection rate.
- xi. Control of the choke valve at the top of the rig so as to control the two-phase flow out of the rig.

3.3 Method of Data processing and Errors and Accuracy

3.3.1 Data Collection

This section provides full detailed information about the procedure of the data collection. However, before starting to run the experiment, some risk assessments were considered. The purpose of data collection in these experiments was to determine the optimum surface gas injection pressure and volume required for a given reservoir pressure and also, to investigate the effect of gas valve port sizes on the gas lift performance. To achieve this objective, numerous pressures, temperature, and surface flow rates were recorded for each test and these data points were then plotted and analyzed. The experiment was carried out into scenarios.

Figure 3.9 illustrates the methodology that was adopted for carrying out in this research. Experimental setup used to collect data for the two different wells (explained in Section 3.2.) applying different parameters like reservoir pressure, gas injection pressure and gas injection rate to obtain the experimental results (see next Chapter).

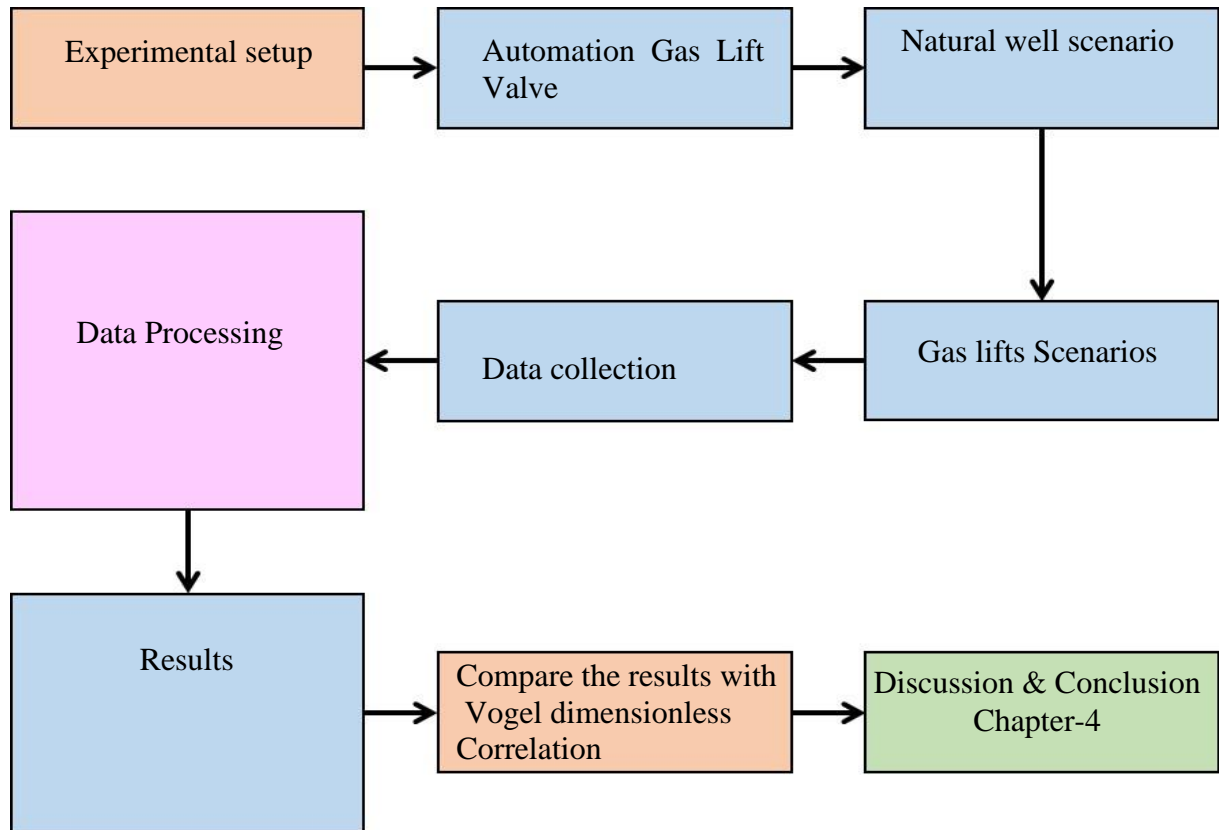


Figure 3.9: Overview of Structure of Procedures

3.3.2 Assumptions

This section provides the full information about the procedure to conduct the results. The following consideration must be taken into the account before running the experiment.

- Utilizing an efficient supply compressor air as the gas lift gas.
- A tap water was used as production fluid because of water denser than oil; the density is a measure of the amount of mass present in a specific volume for a given substance. In the case of water, the strong bonds that exist between the individual molecules mean they are close together. For oil, the individual molecules are much further apart because the forces between the individual molecules are much weaker. As a result, there are a greater number of molecules of water and therefore mass, in the same volume as there are oil

molecules, resulting in water having a higher density than oil. Therefore if we left water it will be easy to lift oil.

- The plastic storage tank is used as reservoir fluid.
- Transparent tubing with the length of the tube is two meters in height and with an inner diameter of 66 mm; outlet diameter of 76 mm, pipe thickness of 5 mm was used as production string.
- An adjustable speed pump system is utilized to match the pressurized reservoir.
- Smart gas lift valve was connected with a control line to provide a real opening or closing and can be operated with a variable opening flow proportional was utilized as gas lift valve.
- A computer program was used to control the gas lift valve operation
- Ability to control the air supply pressure and volume and the fluid enters and out of the system.
- Continuous monitoring the air injection rate and volume and inflow and outflow to maintain efficient gas lift operation.

3.3.3 Inflow Performance for the Natural Flow Well

The oil and gas flow from the reservoir to the surface separator is shown in Figure 3-10.

The total fluid pressure loss from reservoir deep to surface separator is composed of several sections of pressure loss caused by resistance: pressure loss through porous media (first pressure subsystem), pressure loss through well completion section (second pressure subsystem), total pressure loss through tubing string (third pressure subsystem), and total pressure loss through flow line (fourth pressure subsystem) as the following:

- Fluid pressure loss through porous media in accordance with the relation between reservoir pressure, bottom-hole flowing pressure, oil saturation pressure, and the theory of mechanics of fluid through porous media, the pressure distribution relations of single-phase liquid flow, single-phase gas flow, two-phase flow of oil and gas, three-phase flow of oil, gas, and water, and dissolved gas drive and the oil

and gas inflow performance relationship can be derived; thus the total fluid pressure loss through porous media can be determined.

- Fluid pressure loss through well completion section is closely related to the well completion mode and can be calculated by calculating the total skin factor(S) under a different completion mode.
- Total fluid pressure loss through the tubing string can be determined by the calculation under the multiphase flow condition in the tubing string. At present, there are various methods to calculate multi-phase flow in the pipe.
- Total fluid pressure loss through flow line the same calculation method as that of multiphase flow in the pipe is used.

Figure 3.10 illustrates the fluid flow from the storage tank (reservoir) to the surface.

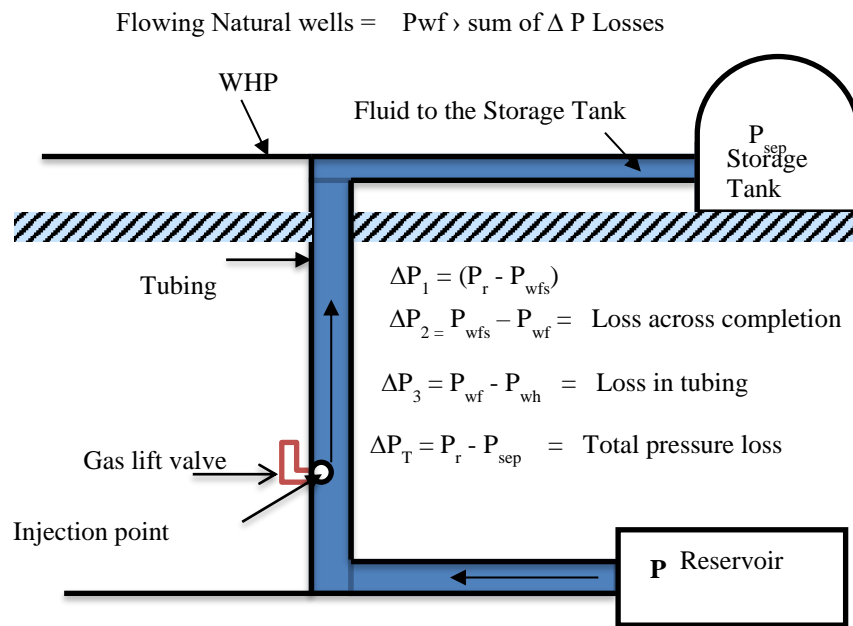


Figure 3.10: Flowing Natural well

3.3.4 Inflow Performance for Gas Lift Well

When the reservoir pressure has depleted to such a low value that stop production, the well needs the assistance of the gas lift systems. In this study, the pump set to a very low pressure to pump the fluid at a certain level, which is above the injection point.

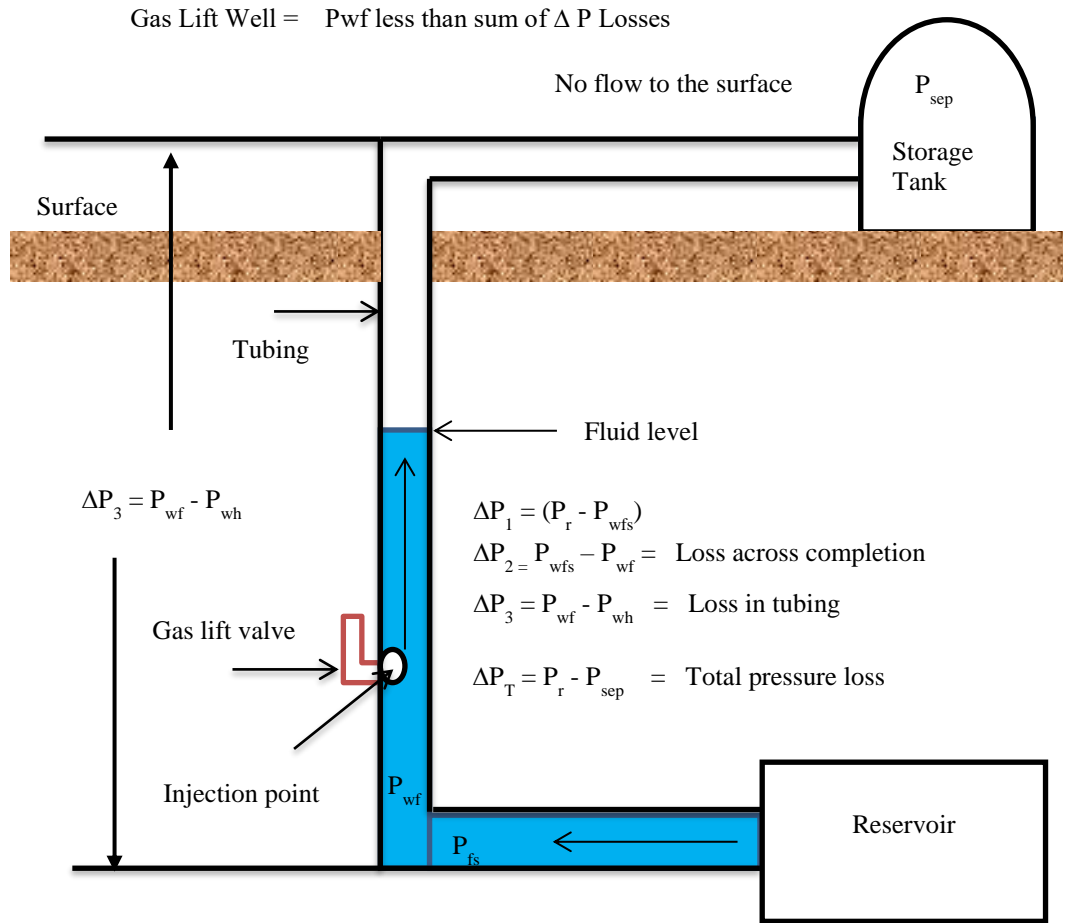


Figure 3.11: Gas Lift Well

Figure 3.11 shows the fluid at carting level inside the tubing string and the reservoir energy cannot be able to push the fluid to the surface and the well has died. In this case, the smart valve will be used to inject gas into the tubing to left the fluid up to the surface.

3.3.5 Operation Parameters

In this study, three main parameters have been considered throughout the experiment to conduct the effect of those in the production.

- **Reservoir Pressure:** Through the reservoir production life, reservoir pressure will decline. Likewise, after water breakthrough, the fluid column weight will increase

as hydrostatic pressure will rise because of increased water and oil mixture density. In this situation, reservoir pressure may not be sufficient to lift up the fluid from bottom to the surface. Several techniques must be applied to avoid the production decline. In these cases, artificial lift techniques are applied to add energy to the produced fluids.

The pressure acting in water at high 2 ft. can be calculated as

$$P = \rho gh$$

P = pressure acting in water at high 2 ft.

ρ = density of pure water 1.940 slugs/ft³

g = specific gravity 32.17405 ft. /s²

$$= (1.940 \text{ slugs/ft}^3) (32.17405 \text{ ft. /s}^2) (2 \text{ ft.}) = 124.835 \text{ lb}_f \text{ /ft}^2 \text{ (psf.)}$$

$$= 0.866 \text{ lbf/in}^2 \text{ (psi)}$$

In this study, the pump was used as reservoir pressure and was controlled to produce proper pressures that were chosen depends on the hydrostatic pressure and the safety of the experimental as shown in Table 3.3.

Table 3.3: The Details Information of the Natural Flow Wells and the Gas Lift Wells			
Well Number	Type of Well	Initial Pump Pressure (psi)	Initial Flow Rate (l/min)
NFW-1	Natural Flow	4.0	25
NFW-2	Natural Flow	2.5	10
GLW-1	Gas Lift (Dead)	1.0	0
GLW-2	Gas Lift (Dead)	0.5	0

- **Gas Injection Rate:** The amount of gas available for the injection process is very important regarding production performance of the field. If limited gas is available for injection the gas must be allocated properly to each well in the field. This helps to maximise the total field oil rate and enhances the gas lift wells performance. In addition, the gas as gas lift gas is costly; however indispensable means to recover oil from high depth reservoir that entails solving the gas lift optimisation problems,

often in response to variations in the dynamics of the reservoir and economic oscillations. In this experiment, the smart gas lift was opened at different port sizes from 4-10 % and applied in the above two different assumed wells.

- **Effect of Injection Pressure on the Well Head Pressure and Production:** Gas lift pressure is a critical design parameter in the gas lift system. It has a major impact on completion design (number of valves), well performance (injection depth), system operating pressure (compressor discharge), and obviously material and equipment specification. Selection of a gas lift pressure that is too high can result in needless investment in compression and other equipment, whereas pressures that are too low can cause loss of production potential and production deferment. In this research, the experimental was operated with different injection pressure to investigate the effect of the injection pressure in the production fluid and the well head pressure. Tables 3.4 and 3.5 show the sample of the data collection records for both Natural Flow Well and Gas Lift Well.

Table 3.4: Results Data Sheet for Well-NWF-1 (Gas Lift Well)



 University of Salford MANCHESTER			Results Data Sheet Date: May 2016 Well State: Well-2 Natural Flow Well									
Well Condition Before Gas Injection			Well Condition After Gas Injection									
Water rate	Water Pump Pressure psig	Well Head Pressure	Valve opening	Injection pressure 29.01 psig			Injection pressure 58.02			Injection pressure 87.02		
l/min	psig	psig	%	Production rate l/min	Well head pressure psig	Increase of production %	Production rate l/min	Well Head Pressure psig	Increase of production %	Production rate	Well head pressure	Increase of production
25	4	1.3	3.85	26.1	0.9	4						
			15.38									
			30.77									
			50.00									
			65.38									
			80.77									
			100									

Table 3.5: Results Data Sheet for Well-3 (Gas Lift Flow Well)

			Results Data Sheet Date: May 2016 Well State: G Flow Well									
Well Condition Before Gas Injection			Well Condition After Gas Injection									
Water rate	Water Pump Pressure psig	Well Head Pressure	Valve opening	Injection pressure 29.01 psig			Injection pressure 58.02			Injection pressure 87.02		
l/min	psig	psig	%	Production rate l/min	Well head pressure psig	Increase of production %	Production rate l/min	Well Head Pressure psig	Increase of production %	Production rate	Well head pressure	Increase of production
0	1	0	3.85	11.8	1.2							
			15.38									
			30.77									
			50.00									
			65.38									
			80.77									
			100									

CHAPTER 4

RESULTS AND DISCUSSIONS

4.1 Overview

As explained in chapter-2, the wells in the oil industry are classified into the two different categories:

- Natural Flow Wells, in which the reservoir pressure is high enough to push the fluid to the top surface.
- Gas Lift Wells (or called dead wells), in which the reservoir pressure is low and it does not have enough energy to push the product out. Therefore an external energy, i.e. gas lift system, required for production.

The gas lift technique can be used for both type of wells explained above. This technique keeps the bottom-hole pressure low enough to provide a high-pressure difference between the reservoir and the bottom-hole. Reduction of the bottom-hole pressure will normally increase the liquid production rate. However, injecting too much gas into the system may cause increasing of the bottom-hole pressure which will lead to declining the production rate due to the back pressure. In order to achieve the optimum production rate, the port size of the gas lift valve and the gas injection pressure (bottom hole) must be controlled to provide a certain amount of gas to improve the productivity. This investigation, therefore, focused on the effect of THREE different gas injection pressures of low (29 psi), medium (58 psi) and high (87 psi) (due to limitation of the experiment) on Production Rate and Well-Head Pressure for both Natural Flow Wells and Gas Lift Wells (or dead wells).

Using the modified simulated apparatus described in the Chapter-3, a number of configurations with respect to Natural Flow Wells and Gas Lift Well together with ‘Smart Gas Left Valve’ were tested.

Table-4.1 summaries of these the results of configurations the following discussed of:

Table 4.4.1: The Details Information of the Natural Flow Wells and the Gas Lift Wells			
Well Number	Type of Well	Initial Pump Pressure (psi)	Initial Flow Rate (l/min)
NFW-1	Natural Flow	4.0	25
NFW-2	Natural Flow	2.5	10
GLW-1	Gas Lift (Dead)	1.0	0
GLW-2	Gas Lift (Dead)	0.5	0

4.2 Effect of Gas Injection Pressure on to the Production Rate and Well-Head

Pressure

As mentioned previously, the gas lift technique can be used for both types of wells (Natural flow wells and the Gas lift wells). This technique keeps the bottom-hole pressure low enough to provide a high-pressure difference between the reservoir and the bottom-hole. In this study, the effect of the injection pressure on to production flow rate was carried out.

The pressure that spikes higher can indicate a problem but more typically will be a cause for concern about damage. A high-pressure event can rupture the wellhead, flow line, a valve or other component, damaging a separator, compressor, or other equipment. It is critical to monitor all pressure conditions at the well head pressure as part of the standard safe operating procedure.

From the previous literature review that indicated the traditional gas lift technologies have design limitations on gas lift valve such as, multi-point of injection, nitrogen charge and, pressure operated valve is very sensitive to well performance condition such as pressure,

temperature and casing pressure. Also, the gas injection rate cannot be controlled [7]. Furthermore, as mentioned in Chapter-2 the operating a gas-lift under low or high gas-lift injection rate has some disadvantage. First, the full lift potential in the gas is not accurately used, resulting in a very inefficient operation. Secondly, pressure surges in production facilities may be so huge that severe operational problems are likely to happen [23]. Furthermore, lift gas flow is not completely controlled. Nevertheless, it was suspected that stability might be brought to the unsteady well by utilizing a control valve to precisely adjust its gas flow. The best gas lift applications use an injection pressured operation valve to regulator lift gas to the well. This means that most engineers can only guess the flow rate being delivered to the bottom of the well. They don't have the ability to correctly control it[19]. In this research, smart gas lift valve has been used to examine the effect of the valve port size and could not have the difficulties raised by these authors.

Gas lift valves, considered to be the heart of the gas lift system of controlling the amount of the gas that enters in the tubing string. In this smart gas lift valve, the gas will be injected continually and monitoring from the surface to prevent and dynamic changes that may happen and if the well performance changes the gas lift injection rate can be increased or decreased depends on the well performance.

4.2.1 Natural flow well: NFW-1

As shown in Table 4.1, the well NFW-1 has been assumed to have 4 psi reservoir pressure and producing 25 lit/min before applying gas injection technique. Although the well is flowing naturally however the gas lifting system can be applied in achieving higher production rate. Table 4.2 presents the results of low gas injection pressure (29 psi) onto the NFW-1 and Figure 4.1 demonstrates these results graphically.

Table 4.4.2: The Results Summary of Low Gas Injection Pressure onto the NFW-1				
Valve Description		Production Rate (l/min)	% of Increase in Production Rate	Well-Head Pressure (psi)
% of Opening	Port Size (mm)			
4	0.25	26.1	4	1.3
15	0.95	26.6	6	0.9
30	1.91	27.0	8	0.9
50	3.18	27.6	10	0.9
65	4.13	27.0	8	0.9
80	5.08	26.5	6	0.9
100	6.35	26.0	4	1.4

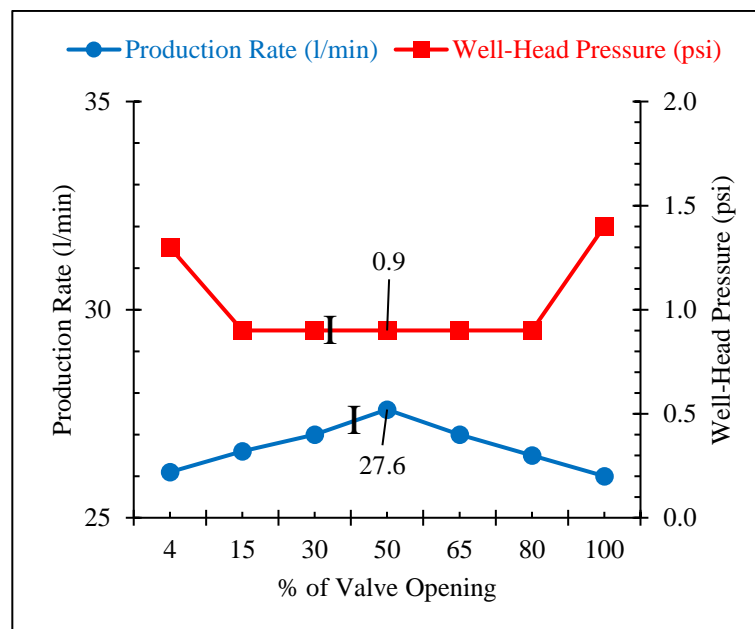


Figure 4.1: Effect of Low Gas Injection Pressure (29 psi) for NFW-1

As shown in Figure 4.1, the overall result indicates that the production rate for NFW-1 will increase from 25 lit/min from the baseline with the application of low gas injection pressure of 29 psi. Figure 4.1 also shows that the improvement on production rate is made at about 4% on the commencement of the gas injection process. This can be aligned to 4% of the valve port size opening (or 0.25 mm port size diameter) in which the wellhead pressure is at the maximum level of 1.3 psi (as shown in Figure 4.1). The production rate will then rise to the maximum value of 27.6 lit/min with the 50% opening of the valve port size (or 3.18 mm port size diameter). This increase is due to the reduction of the well-head pressure from 1.3 psi to 0.9 psi that provides more pressure drop in order to push the liquid to the surface. The production rate eventually declines to 26 lit/min when the valve is fully open and the well-head pressure increase to the maximum value. As described in Chapter-2 this reduction of flow rate is due to the introduction of more gas being injected onto the system which generating gas bubbles within the liquid column. These gas bubbles tend to combine and form the slug characteristics within the production tubing thus it will partially block the production tubing. Injecting high amounts of gas raises the bottom-hole pressure that leads to a reduction of the production rate. This is due to the high gas injection rate that causes slippage. In this case, the gas phase moves quicker than the liquid phase, leaving the liquid phase behind and a smaller amount of liquid will flow along the tubing. Therefore, there should be an optimum gas injection rate [8]. Although the control of pore-size could be cumbersome with smart valve system this problem can be mitigated.

Table 4.3 summarizes the results of medium gas injection pressure (58psi) onto the NFW-1 and Figure 4.2 presents these results graphically.

Table 4.4.3: The Results Summary of Medium Gas Injection Pressure onto the NFW-1				
Valve Description		Production Rate (lit/min)	% of Increase in Production Rate	Well-Head Pressure (psi)
% of Opening	Port Size (mm)			
4	0.25	29.0	16	1.2
15	0.95	29.5	18	1.0
30	1.91	31.0	24	1.0
50	3.18	30.2	21	1.0
65	4.13	30.0	20	1.0
80	5.08	29.5	18	1.0
100	6.35	29.1	16	1.3

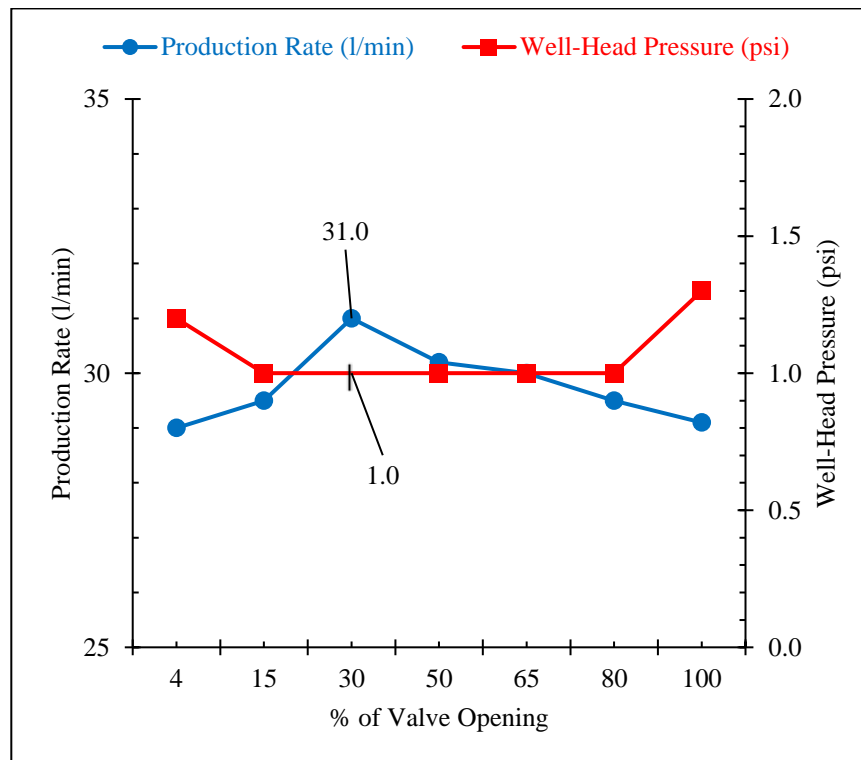


Figure 4.2: Effect of Medium Gas Injection Pressure (58 psi) for NFW-1

Figure 4.2 shows the overall improvement of the production rate on NFW-1 with medium gas injection pressure at 58 psi. The result indicates that the flow rate increased to 29

lit/min (about 16% improvement on flow rate) from the baseline of 25 lit/min at the beginning of the gas injection when the valve port size is partially open at 4% (or 0.25mm port size diameter). The wellhead pressure is also 1.2 psi which is the highest value. The production rate will then rise gradually to the optimum level of 31.0 lit/min with the 30% opening of the valve port size (or 1.91mm port size diameter). This increase shows the improvement of 24% in the production rate. Furthermore, the well-head pressure reduces to 1.0 psi which provides higher-pressure drop and hence the better improvement on the production rate. The wellhead pressure then remains constant whereas the flow rate slightly decreases to 29.5 lit/min when the valve port size is 80% open (or 5.08 mm port size diameter). Opening the valve fully increases the wellhead pressure to 1.3 psi in which the production rate is at the minimum level of 29.1 lit/min. Comparing the maximum level of the of flow rate obtained at medium gas injection pressure with those using low gas injection pressure shows better achievement in production which is about 3.4 lit/min in difference (27.6 lit/min with low gas injection pressure and 31 lit/min when the medium gas injection pressure used).

Table 4.4 summarizes the results of high gas injection pressure (87 psi) onto the NFW-1 and Figure 4.3 presents these results graphically.

Table 4. 4.4: The Results Summary of High Gas Injection Pressure onto the NFW-1				
Valve Description		Production Rate (lit/min)	% of Increase in Production Rate	Well-Head Pressure (psi)
% of Opening	Port Size (mm)			
4	0.25	29.3	17	1.0
15	0.95	31.0	24	1.0
30	1.91	28.7	15	1.0
50	3.18	27.6	10	1.2
65	4.13	27.2	9	1.2
80	5.08	26.0	4	1.4
100	6.35	25.5	2	1.5

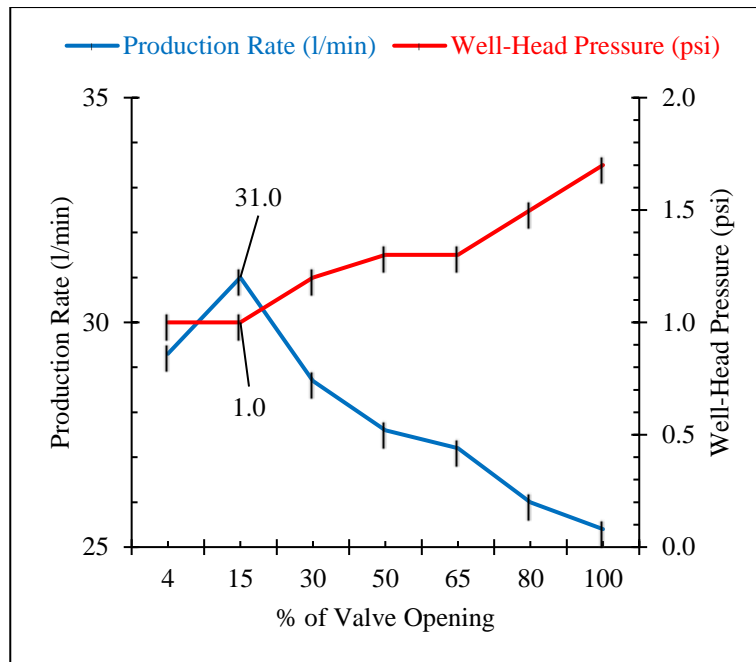


Figure 4.3: Effect of High Gas Injection Pressure (87 psi) for NFW-1

Results shown in Figure 4.3, presents the maximum production rate of 31.0 lit/min (or 24% improvement on production) could be achieved when the high gas injection pressure at 87 psi is used and when the valve is 15% open (or 0.95mm port size diameter). The flow rate then decreases sharply to the minimum level of 25.5 lit/min in which comparing this value with the 25 lit/min at the baseline shows that the production has been stopped. The well-head pressure is at 1.0 psi at the commencing of the gas injection and it remains constant until the production rate reaches the maximum level. It will then rise dramatically to 1.7 psi when the valve is fully open. This issue caused by injection of too much gas into the system in which the gas bubbles within the production tubing are generating rapidly and since the injection of the pressure is higher, therefore, they combined together faster than injection at low pressure. Thus the complete blockage will occur and the production will stop.

Figure 4.4 shows the comparison of the all three gas injection pressures onto the NFW-1.

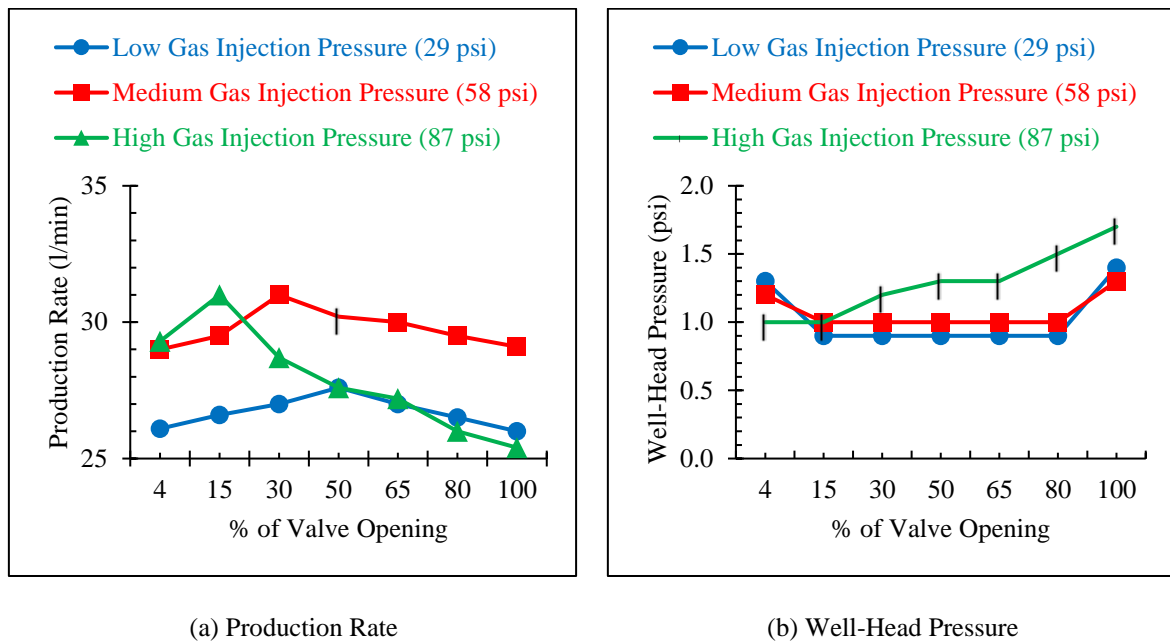


Figure 4.4: Summary of Different Gas Injection Pressures on Production Rate for NFW-1

Although NFW-1 flows naturally however as shown in Figure 4.4, the application of gas lifting system with different gas injection pressures helps to increase the production rate (see Figure 4.4(a) as well as maintaining the well-head pressures (see also Figure 4.4(b)). Injections the gas at low and medium pressures increase the production rate constantly and the well-head pressures differ slightly. The gas bubbles generating within the liquid column by using these two injection pressures can be controlled better compare to the injection of the gas at high pressure. When the gas is injected at high pressure, a slight increase in the valve port size can block the production tubing due to the generating of the too much gas bubbles and rapid increase of well-head pressure. Therefore using the novel method of gas injection using a smart gas lift valve can assure the user to control and monitor the valve port size from the surface at all the time and reduce or increase the valve port size as required.

4.2.2 Vogel dimensionless Correlation for the well NFW-1

As mentioned previously in Table 4.1, the well has been assumed to have 4 psi reservoir pressure and producing 25 l/min before applying gas injection technique. Also, as mentioned in Chapter-2 the Vogel Correlation (Eq-2.5), [25], proposed the following correlation for predicting a well's inflow performance under a solution gas drive (two-phase flow) conditions based on a large number of well performance simulations. As the assumed well produces by gas lift system that means the well under the bubble point pressure, in this case, Vogel correlation can be applied.

Vogel's inflow performance relationship relates the flowing well pressure to production rate for solution-gas drive reservoirs. Because two-phase flow exists, the graph of bottom-hole flowing pressures versus oil production rate results in a curved line. This trend accounts for the decrease in production as more gas comes out of the solution. Vogel assumes the initial reservoir pressure is the same as the bubble point pressure for the starting point of the IPR curve. This implies no gas has initially come out of the solution, i.e. the reservoir is at bubble point pressure, as studied in this research, the gas lift well that means the reservoir produces below the bubble point pressure so the saturated reservoirs. To use this correlation, to determine the production rate and flowing bottom-hole pressure from a production test and obtain an estimate of the average reservoir pressure at the time of the test. With this information, the maximum oil production rate can be estimated and used to estimate the production rates for other flowing bottom-hole pressures at the current average reservoir pressure.

Vogel normalized the calculated IPR and expressed the relationships in a dimensionless form

$$\frac{P_{wf}}{P_r} = \text{Pressure dimensionless}$$

$$\frac{Q}{Q_{max}} = \text{Flow rate dimensionless}$$

By using dimensionless pressures and rates, Vogel found well productivity could be described by equation 2.5

$$\frac{Q}{Q_{max}} = 1 - 0.2 \left(\frac{P_{wf}}{P_r} \right) - 0.8 \left(\frac{P_{wf}}{P_r} \right)^2$$

The inflow performance relationship of a well is a relationship between its producing bottom-hole pressure and its corresponding production rates under a given reservoir condition. The preparations of inflow performance relationship curves for oil wells are extremely important in production system analysis. Unless some idea of the productive capacity of a well can be established the design and optimization of the system of the well becomes difficult. Solution gas escapes from the oil and becomes free gas when the reservoir pressure falls below the bubble point pressure. During this state of pressure decline, oil and gas (two-phase flow) exist in the whole reservoir. The presence of free gas leads to reduced relative permeability and increased oil viscosity. The synergies of these two effects result in lower oil production rates. This makes the IPR curve deviate from linear trend below the bubble point pressure. This research modifies the Vogel IPR curve for use in wells within reservoirs that are below the bubble point pressure. Furthermore, the decrease in flowing bottom-hole pressure will lead to the increase in producing production rate [22].

From the previous, Figure 4.4(a) which shows the maximum production rates were 27.6, 31.1 for the low, medium and high-pressure injection respectively. The maximum production rate results which were obtained from different injection pressure divided by

the initial production rate 25 lit/min, Therefore Q/Q_{\max} will be equal 0.91, 0.81 for low, and high-pressure injection rate respectively and by knowing the Q/Q_{\max} the P_{wf}/P_r will be determined. The results were plotted in x-axis also, the flowing well head pressures were divided by average reservoir pressure and the results were plotted in y-axis plotted as shown in Figure 4.5.

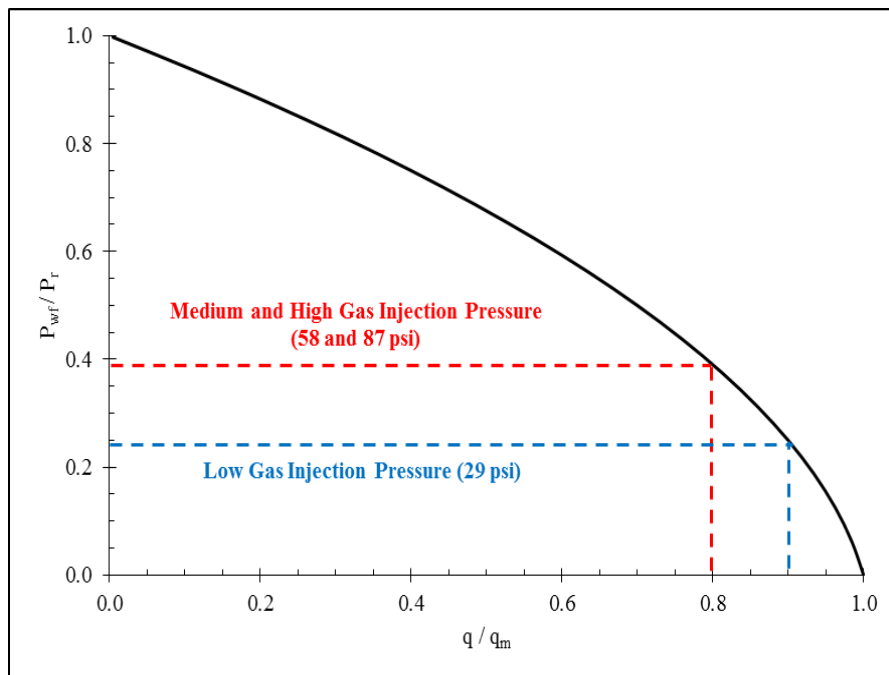


Figure 4.5: Experimental results validated with Vogel Equation

From Figure 4.5 it is clearly remarkable that increase the injection pressure led to reducing the production rate. This is because very high gas injection causes slippage, where gas phase moves faster than liquid phase, leaving the liquid phase behind. In this condition, tubing pressure should be optimized with respect to the amount of gas injection rate. Furthermore, Figure 4.5 illustrates that the gas-lift pressure is a critical design parameter in the gas-lift system design. It has a major impact on gas lift design number of valves, well

performance injection depth, system operating pressure compressor discharge, and obviously maternal and equipment specification all of which will have a significant impact on costs. Selection of a gas-lift pressure that is too high can result in needless investment in compression and other equipment, whereas pressures that are too low can cause loss of production potential and production deferment. However, by utilizing smart gas lift the gas injection can be controlled depends on the flow rate required. By observed, the out let flow at the surface of the production fluid if deceased the gas injection will be increased from the surface and if the injection is too high the gas injection can be optimized. Furthermore, the results show that bottom-hole pressures and well head pressure are known. By comparing these pressures the production rate can determine.

4.2.3 Natural Flow Well (NFW-2)

As shown in Table 4.1, the well has been assumed to have 2.5 psi reservoir pressure and producing 10 lit/min before applying gas injection technique. Although the well is flowing naturally, however, the reservoir pressure has reduced and the natural flow rate indicates that the well needs the gas lifting system to achieve higher production rate. Table 4.5 presents the results of low gas injection pressure (29 psi) onto the NFW-2 and Figure 4.6 demonstrates these results graphically.

Table 4.4.5: The Results Summary of Low Gas Injection Pressure onto the NFW-2				
Valve Description		Production Rate (l/min)	% of Increase in Production Rate	Well-Head Pressure (psi)
% of Opening	Port Size (mm)			
4	0.25	13.7	37	1.0
15	0.95	14.1	41	1.0
30	1.91	14.3	43	1.0
50	3.18	14.3	43	1.0
65	4.13	14.0	40	1.0
80	5.08	13.1	31	1.0
100	6.35	13.0	30	1.0

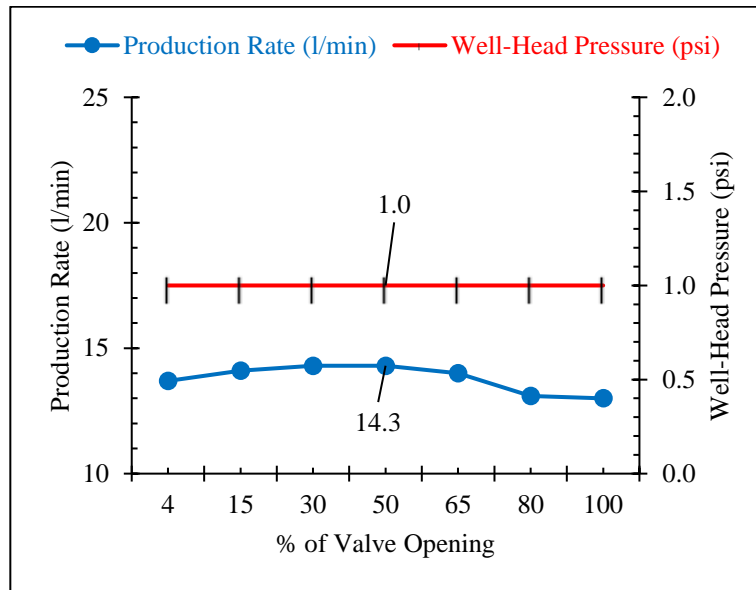


Figure 4.6: Effect of Low Gas Injection Pressure (29 psi) for NFW-2

As shown in Figure 4.6, the overall result indicates that the production rate for NFW-2 will increase from 10 lit/min from the baseline with the application of low gas injection pressure of 29 psi. As shown in Table 4.5, the improvement on production rate is made at about 4% on the commencement of the gas injection process. This can be aligned to 37% of the valve port size opening (or 0.25mm port size diameter). The production rate will then increase gradually to the maximum value of 14.3 lit/min (about 43% improvement on the flow rate) with the 50% opening of the valve port size (or 3.18 mm port size diameter). The production rate eventually declines to 13.0 lit/min when the valve is fully open. Since the production rate is not fluctuating too much from the beginning of the gas injection when the valve is partially open till fully open, therefore the pressure drop between the reservoir pressure and the top surface remains constant and the well-head pressure is not changing a lot and it is about 1.0 psi from beginning to the end.

Table 4.6 summarizes the results of medium gas injection pressure (58 psi) onto the NFW-2 and Figure 4.7 presents these results graphically.

Table 4.4.6: The Results Summary of Medium Gas Injection Pressure onto the NFW-2				
Valve Description		Production Rate (lit/min)	% of Increase in Production Rate	Well-Head Pressure (psi)
% of Opening	Port Size (mm)			
4	0.25	14.5	45	1.2
15	0.95	15.3	53	1.1
30	1.91	15.5	55	1.0
50	3.18	15.0	50	1.1
65	4.13	13.7	37	1.2
80	5.08	13.0	30	1.2
100	6.35	12.2	22	1.3

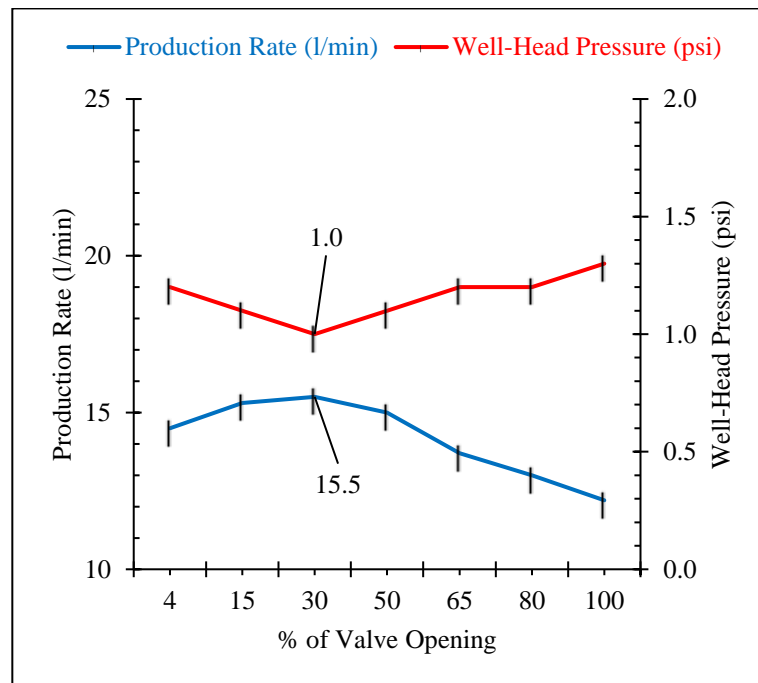


Figure 4.7: Effect of Medium Gas Injection Pressure (58 psi) for NFW-2

Figure 4.7 shows the overall improvement of the production rate on NFW-2 with medium gas injection pressure at 58 psi. The result indicates that the flow rate increased to 14.5 lit/min (about 45% improvement on flow rate) from the baseline of 10 lit/min at the

beginning of the gas injection when the valve port size is partially open at 4% (or 0.25mm port size diameter). Since the gas is injected at higher pressure compared to the reservoir pressure, the pressure drop will occur and the results shown in Figure 4.7 indicate that the well-head pressure starts to be 1.2 psi. Increasing the production rate decreases the well-head pressure to the minimum level of 1.0 psi in which the production rate rises to the maximum value of 15.5 lit/min with the 30% opening of the valve port size (or 1.91mm port size diameter). This increase shows the improvement of 55% in the production tubing as can be seen in Table 4.6. Furthermore, opening the valve port size injects too much gas and thus the well-head pressure increases to 1.3 psi in which the production rate decreases to the 12.2 lit/min when the valve is fully open (100% opening or 6.35mm port size diameter). Moreover, injecting too much gas will produce more gas bubbles which will then combine and form the slug formations that causes blockage in the production tubing. Comparing the maximum level of the of flow rate obtained at medium gas injection pressure with those using low gas injection pressure shows better achievement in the production which is about 1.2 lit/min in difference (14.3 lit/min with low gas injection pressure and 15.5 lit/min when the medium gas injection pressure used).

Table 4.7 summarizes the results of high gas injection pressure (87 psi) onto the NFW-2 and Figure 4.8 presents these results graphically.

Table 4.4.7: The Results Summary of High Gas Injection Pressure onto the NFW-2				
Valve Description		Production Rate (lit/min)	% of Increase in Production Rate	Well-Head Pressure (psi)
% of Opening	Port Size (mm)			
4	0.25	15.0	50	1.1
15	0.95	18.3	83	0.9
30	1.91	15.6	56	1.1
50	3.18	14.9	49	1.2
65	4.13	14.5	45	1.2
80	5.08	14.0	40	1.4
100	6.35	13.7	37	1.5

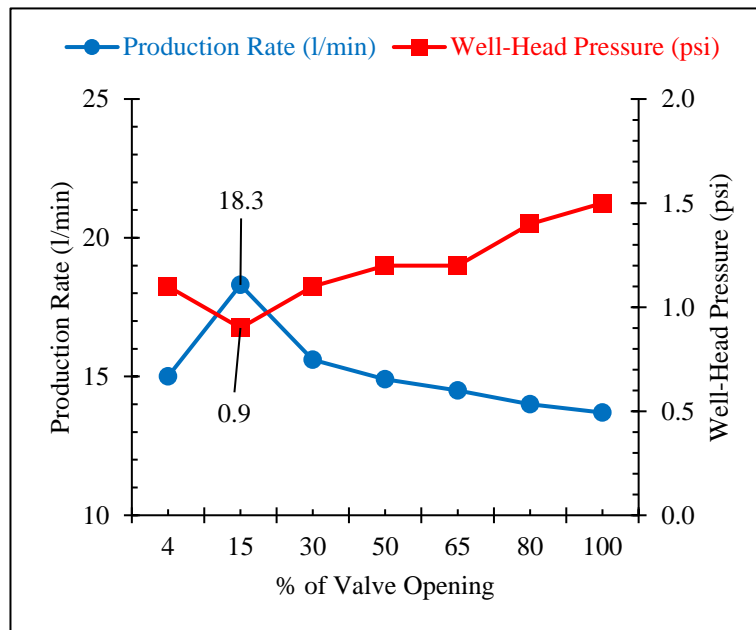


Figure 4.8: Effect of High Gas Injection Pressure (87 psi) for NFW-2

Results shown in Figure 4.8, presents the maximum production rate of 18.3 lit/min (with 83% improvement on production) could be achieved when the high gas injection pressure at 87 psi is used and when the valve is 15% open (or 0.95mm port size diameter). Also, the wellhead pressure reaches to the minimum value of 0.9 psi in which high-pressure drop

between the reservoir pressure and the top surface will occur. Opening the valve port size, injects too much gas and the flow rate then decrease sharply to the minimum level of 13.7 lit/min in which the wellhead pressure is at the maximum value of 1.5 psi. This issue, as explained previously, caused by injection of too much gas into the system in which the gas bubbles within the production tubing are generating rapidly and since the injection of the pressure is higher, therefore, they combined together faster than injection at low pressure. Thus the complete blockage will occur and the production will stop.

Figure 4.9 shows the comparison of the all three gas injection pressures onto the NFW-2.

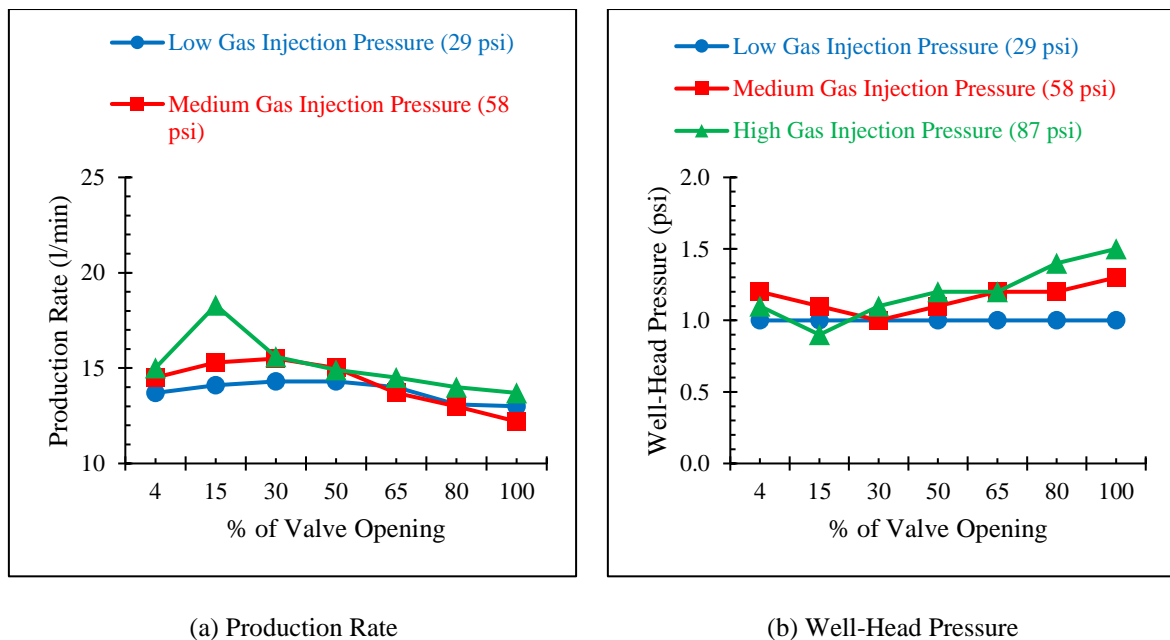


Figure 4.9: Summary of Different Gas Injection Pressures on Production Rate for NFW-2

As explained before, the NFW-2 flows naturally, however, the reservoir pressure is very low which means after a while the well could be considered as a dead well. Therefore, the external energy requires improving the production rate. However, it should be noted that since the reservoir pressure is low (about 2.5 psi), therefore the injection of gas must be controlled in order to avoid high well-head pressure thus reducing the production rate. As

can be seen in Figure 4.9 (b), the well-head pressure for all three different gas injection pressures must be between 0.9 – 1.0 psi for achieving higher production rate. The results in this Figure also show that injection the gas at low pressure is producing constant well-head pressure; therefore, the valve at any port size diameter could assist the production rate. However, the control of the valve port size for medium pressure and high-pressure gas injection is very important since any increase in the gas discharge rate will reduce the production rate.

4.2.4 Vogel Dimensionless Correlation for the Well NFW-2

All well deliverability equations relate the well production rate and the driving force in the reservoir, that is, the pressure difference between the initial, outer boundary or average reservoir pressure and the flowing bottom-hole pressure. If the bottom-hole pressure is given, the production rate can be obtained readily. However, the bottom-hole pressure is a function of the wellhead pressure, which, in turn, depends on production engineering decisions, separator or pipeline pressures, etc. Therefore, what a well will actually produce must be the combination of what the reservoir can deliver and what the imposed wellbore hydraulics would allow. Furthermore, liquid flow into a well depends on both the reservoir characteristics and the surface flowing pressure. The relationship of liquid inflow rate to bottom-hole flowing pressure is called the IPR (Inflow Performance Relationship). By plotting this relationship, the well's flow potential or rate can be determined at various flowing surface pressures as shown in Figure 4.10. This process, called IPR analysis, can be used to determine deliverability for well-producing oil. In this study, Vogel dimensionless Correlation (eq2.5) was used in validation of the present results using the smart gas lift in the present study.

As mentioned in Chapter-2, Productivity of an oil well draining a solution-gas drive reservoir was investigated by Vogel using numerical simulation. Vogel used a computer model to generate IPR (Inflow Performance Relationship) for a total of 21 simulations covering a wide range of oil, PVT properties, and relative permeability's were made. It appeared that if several solution-gas "drive reservoirs were examined with the aid of this program, empirical relationships might be established that would apply to solution-gas drives reservoirs in general. Vogel normalized the calculated IPR and expressed the relationships in a dimensionless form.

$$\frac{P_{wf}}{P_r} = \text{Pressure dimensionless}$$

$$\frac{Q}{Q_{max}} = \text{Flow rate dimensionless}$$

By using dimensionless pressures and rates, Vogel found well productivity could be described by equation 2.5 Accurate prediction of the production rate of fluids from the reservoir into the wellbore is essential for efficient artificial lift installation design. In order to design a gas lift installation, it is often necessary to determine the well's producing rate. The accuracy of this determination can affect the efficiency of the design. From the previous Figure 4.9, it is clearly seen that production rose to the maximum value for the well NFW-2 with the 15% opening (14.9, 15.3 and 18.3 l/min) for the low, medium and high pressure respectively and Q/Q_{max} the equal 0.70, 0.65 and 0.55 l/min. respectively. The performance of a solution gas-drive reservoir can be predicted using Vogel inflow performance relation (or IPR), which simply relates the deliverability of a well to bottom-hole pressure and average reservoir pressure. The maximum production rate results which were obtained from different injection pressure divided by the initial production rate 25lit/min, the results were plotted in x-axis also, the flowing well head pressures were divided by average reservoir pressure and the results were plotted in y-axis plotted. Figure

4.10 shows low injection pressure gives more production rate this is due differential pressure between the reservoir pressure and well head pressure is very low. As mentioned previously injection high amount of gas leads to reduce the production rate.

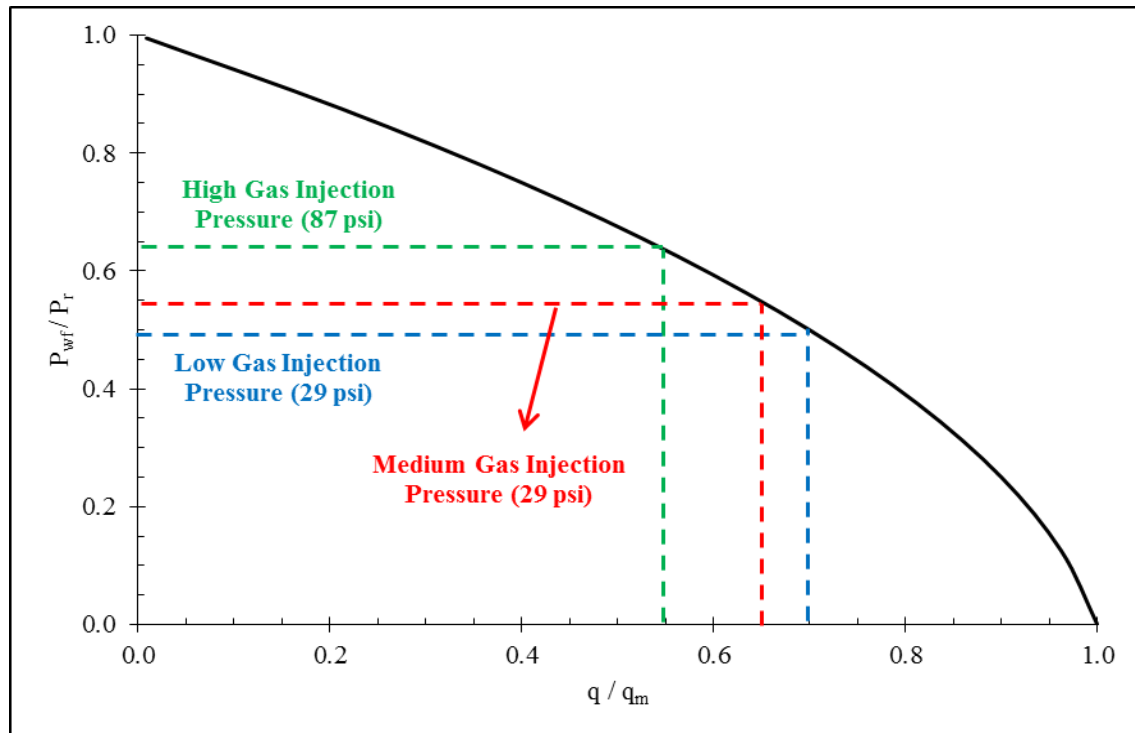


Figure 4.10: Experimental results validated with Vogel Equation

Figure 4.10 illustrates that the gas-lift pressure is a critical design parameter in the gas-lift system design. It has a major impact on completion design number of valves, well performance injection depth, system operating pressure compressor discharge, and obviously maternal and equipment specification all of which will have a significant impact on costs. Selection of a gas-lift pressure that is too high can result in needless investment in compression and other equipment, whereas pressures that are too low can cause loss of production potential and production deferment. To study the effect of injection pressure three different pressures low (29), medium (58) and high (87) psig were applied and plotted versus. It is clearly remarkable that increase the injection pressure led to reducing

the production rate. This is because very high gas injection causes slippage, where gas phase moves faster than liquid phase, leaving the liquid phase behind. In this condition, tubing pressure should be optimized with respect to the amount of gas injection rate. However, by utilizing smart gas lift the gas injection can be controlled depends on the flow rate required. By observed, the out let flow at the surface of the production fluid if deceased the gas injection will be increased from the surface and if the injection is too high the gas injection can be optimized.

4.3 Gas Lift Wells

4.3.1 Gas Lift Well (GLW-1)

As shown in Table 4.1, the well has been assumed to be partially dead at 1.0 psi reservoir pressure but without any production. It should also be noted that the height of the liquid column is very close to the top surface, however since the reservoir pressure is not strong enough, thus the liquid cannot rise anymore. Therefore to achieve the production the gas lift system must be applied.

Table 4.8 presents the results of low gas injection pressure (29 psi) onto the GLW-1 and Figure 4.11 demonstrates these results graphically.

Table 4. 4.8: The Results Summary of Low Gas Injection Pressure onto the GLW-1				
Valve Description		Production Rate (l/min)	% of Increase in Production Rate	Well-Head Pressure (psi)
% of Opening	Port Size (mm)			
4	0.25	10.0	N/A	1.2
15	0.95	11.8		1.2
30	1.91	12.8		1.2
50	3.18	14.0		1.0
65	4.13	13.5		1.1
80	5.08	13.0		1.1
100	6.35	12.8		1.1

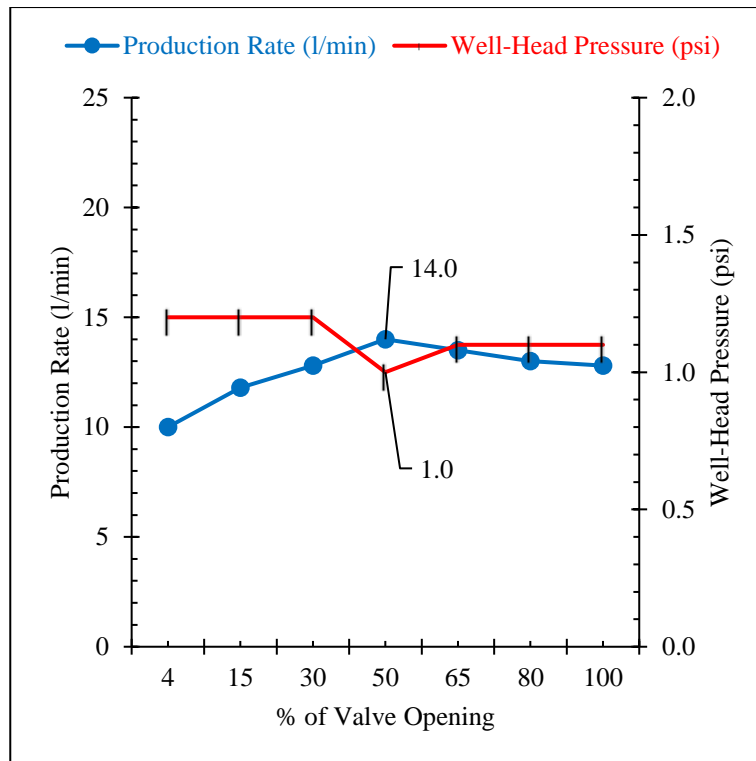


Figure 4.11: Effect of Low Gas Injection Pressure (29 psi) for GLW-1

As shown above, in Figure 4.11, full production can be achieved with using low gas injection pressure at 29 psi. The flow rate starts at 10 lit/min at the beginning of the injection process when the valve is 4% open (or 0.25mm port size diameter). The flow rate will then increase gradually as the valve port size is opening to be half open (50% opening or 3.18mm port size diameter) and it will reach the maximum level of 14 l/min. Afterward, the production rate declines slightly to 12.8 l/min when the valve is fully open. The wellhead pressure in GLW-1 starts to be 1.2 psi at the beginning of the gas injection and it remains constant to the 30% valve opening (or 1.91mm port size diameter). When the production rate is at the optimum level, the well-head pressure drops to 1.0 psi which is the minimum value and provides high-pressure drop between the reservoir pressure and the top surface. Subsequently, the well-head pressure starts to rise again to reach 1.1 psi in

which the production rate decreases. The results shown above demonstrate that the production rate in GLW-1 can be controlled easily from the top surface since the well-head pressure varies slightly and the valve port size can be controlled from 4% opening to 50% (or from 0.25mm port size diameter to 3.18mm).

Table 4.9 summarizes the results of medium gas injection pressure (58 psi) onto the GLW-1 and Figure 4.12 presents these results graphically.

Table 4. 4.9: The Results Summary of Medium Gas Injection Pressure onto the GLW-1				
Valve Description		Production Rate (lit/min)	% of Increase in Production Rate	Well-Head Pressure (psi)
% of Opening	Port Size (mm)			
4	0.25	14.0	N/A	1.4
15	0.95	14.4		1.4
30	1.91	14.8		1.4
50	3.18	16.4		1.1
65	4.13	15.8		1.3
80	5.08	15.0		1.3
100	6.35	13.9		1.4

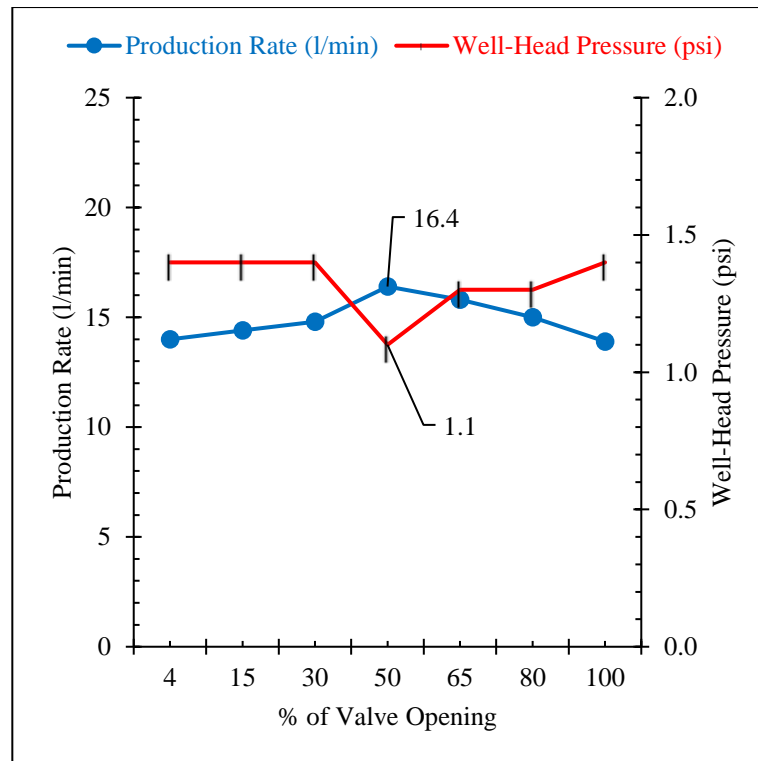


Figure 4.12: Effect of Medium Gas Injection Pressure (58 psi) for GLW-1

The results shown in Figure 4.12 shows the production rate starts to increase at 4% valve opening from 14 l/min and it will increase to the maximum value of 16.4 lit/min when the valve is 50% open (or 3.18mm port size diameter). The well-head pressure also remains constant from 1.4 psi and when the production rate reaches the maximum level, the well-head pressure drops to 1 psi. Injection too much gas with the opening of the valve port size reduces the flow rate to 13.9 lit/min when the valve is fully open in which the well-head increases to the initial value of 1.4 psi. This issue is due to the injection of too much gas that produces gas bubbles which will then forms to be the slug and thus block the production tubing partially. Comparing the maximum level of the of flow rate obtained at medium gas injection pressure with those using low gas injection pressure shows better

achievement in production which is about 2.4 lit/min in difference (14 lit/min with low gas injection pressure and 16.4 lit/min when the medium gas injection pressure used).

Table 4.10 summarizes the results of high gas injection pressure (87 psi) onto the GLW-1 and Figure 4.13 presents these results graphically.

Table 4.4.10: The Results Summary of High Gas Injection Pressure onto the GLW-1				
Valve Description		Production Rate (lit/min)	% of Increase in Production Rate	Well-Head Pressure (psi)
% of Opening	Port Size (mm)			
4	0.25	15.5	N/A	1.6
15	0.95	16.2		1.5
30	1.91	17.5		1.3
50	3.18	18.2		1.2
65	4.13	15.5		1.5
80	5.08	12.1		1.7
100	6.35	10.9		1.8

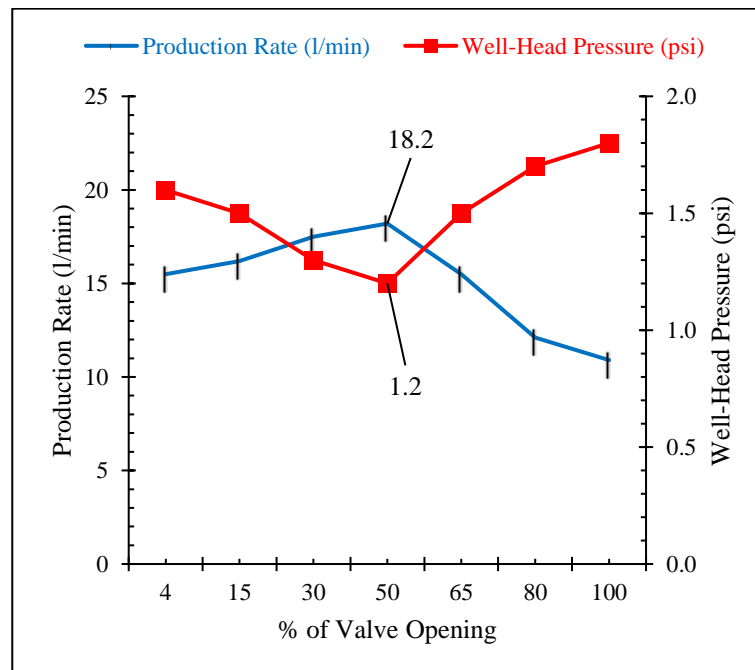


Figure 4.13: Effect of High Gas Injection Pressure (87 psi) for GLW-1

Results shown in Figure 4.13, presents the maximum production rate of 18.2 l/min could be achieved when the high gas injection pressure at 87 psi is used at 50% of the valve

opening (or 3.18mm port size diameter). Also, the well-head pressure reaches to the minimum value of 1.2 psi in which high-pressure drop between the reservoir pressure and the top surface will occur. Opening the valve port size, injects too much gas and the flow rate then decrease sharply to the minimum level of 10.9 lit/min in which the wellhead pressure is at the maximum value of 1.8 psi. This issue, as explained previously, caused by injection of too much gas into the system in which the gas bubbles within the production tubing are generating rapidly and since the injection of the pressure is higher, therefore, they combined together faster than injection at low pressure. Thus the complete blockage will occur and the production will stop. Figure 4.14 shows the comparison of the all three gas injection pressures onto the GLW-1.

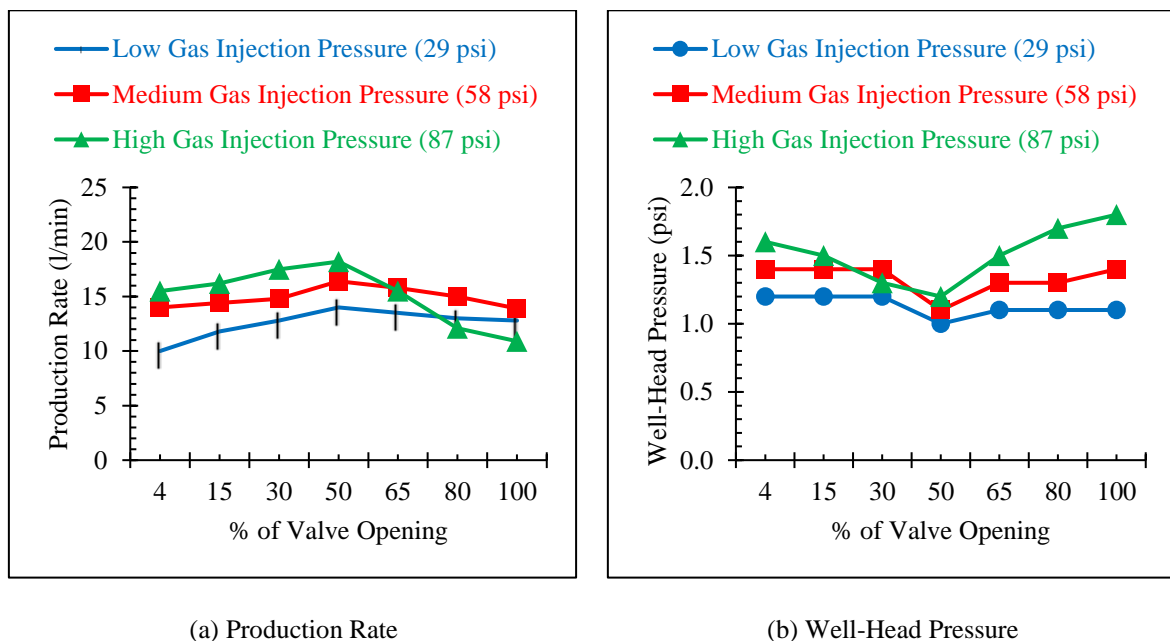


Figure 4.14: Summary of Different Gas Injection Pressures on Production Rate for GLW-1

The comparison results of the production rate with injection different gas pressures show that using a low gas injection pressure assist the well to be producible (see Figure 4.14(a)) and it will keep the well-head pressure almost constant (see also Figure 4.14(b)). This

result also demonstrates that the optimum well-head pressure should be between 1.0 to 1.2 psi in order to achieve maximum production rate for different gas injection pressures. However, applying the gas injection at lower pressure will keep the production rate almost constant in which the valve port size can be controlled and monitored easily compare it with high-pressure gas injection which shows that the production rate will be increased from 4% to 50% opening and after that the reduction of flow rate will occur.

4.3.2 Gas Lift Well (GLW-2)

As shown in Table 4.1, the well has been assumed to be completely dead at 0.5 psi reservoir pressure without any production. It should also be noted that the height of the liquid column is lower than GLW-1 and it is slightly above the gas injection port, therefore to achieve the production the gas lift system must be applied. Table 4.11 presents the results of low gas injection pressure (29 psi) onto the GLW-2 and Figure 4.15 demonstrates these results graphically.

Table 4.4.11: The Results Summary of Low Gas Injection Pressure onto the GLW-2				
Valve Description		Production Rate (l/min)	% of Increase in Production Rate	Well-Head Pressure (psi)
% of Opening	Port Size (mm)			
4	0.25	3.0	N/A	0.8
15	0.95	3.2		0.8
30	1.91	3.6		0.7
50	3.18	3.9		0.6
65	4.13	4.0		0.6
80	5.08	3.4		0.7
100	6.35	3.0		0.8

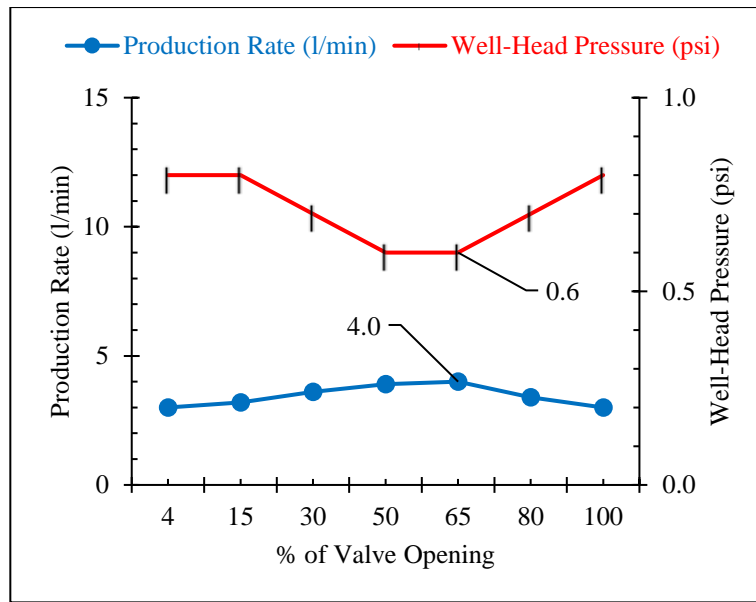


Figure 4.15: Effect of Low Gas Injection Pressure (29 psi) for GLW-2

As shown above, in Figure 4.15, the GLW-2 can be a productive well with applying low gas injection pressure at 29 psi. The flow rate starts at 3 l/min at the commencing of the gas which is injected at the lower pressure when the valve is 4% open (or 0.25mm port size diameter). The flow rate will then increase gradually to the maximum level of 4 l/min when the valve port size is 4.13mm (or 65% open). The production rate will then decrease slightly to 3 l/min again when the valve is fully open. Since the reservoir is depleted completely and it does not have pressure, therefore any injection pressure will affect the well-head pressure. As is shown in Figure 4.15, the well-head pressure begins with 0.8 psi at the beginning of the gas injection and it will reduce to 0.6 psi when the production rate achieves at the higher value. Although the production rate decreases slightly when the valve opens more, the well-head pressure increases more to 0.8 psi. This is due to the more gas injection which creates gas bubbles.

Table 4.12 summarizes the results of medium gas injection pressure (58 psi) onto the GLW-2 and Figure 4.16 presents these results graphically.

Table 4.4.12: The Results Summary of Medium Gas Injection Pressure onto the GLW-2				
Valve Description		Production Rate (lit/min)	% of Increase in Production Rate	Well-Head Pressure (psi)
% of Opening	Port Size (mm)			
4	0.25	4.5	N/A	0.7
15	0.95	4.7		0.7
30	1.91	4.9		0.6
50	3.18	5.3		0.5
65	4.13	5.2		0.6
80	5.08	5.0		0.6
100	6.35	4.2		0.7

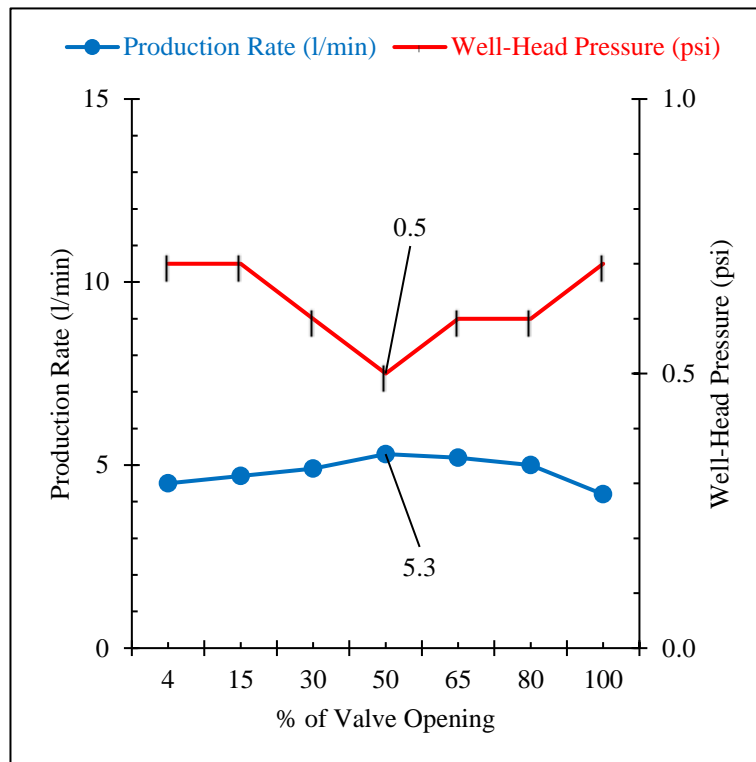


Figure 4.16: Effect of Medium Gas Injection Pressure (58 psi) for GLW-2

The results shown in Figure 4.16 presents the production rate starts to increase at 4% valve opening from 4.5 l/min and it will increase to the maximum value of 5.3 l/min when the

valve is 50% open (or 3.18mm port size diameter). The well-head pressure is also decreased from 0.7 psi at the beginning of the gas injection to 0.5 psi when the maximum flow rate occurs. Opening the valve port size to be fully open, increases the well-head pressure to 0.7 psi thus reduces the flow rate to 4.2 l/min when the port size diameter is 6.35mm (or 100% open). Comparing the maximum level of the of flow rate obtained at medium gas injection pressure with those using low gas injection pressure shows better achievement in production which is about 1.3 lit/min in difference (4 lit/min with low gas injection pressure and 5.3 lit/min when the medium gas injection pressure used).

Table 4.13 summarizes the results of high gas injection pressure (87 psi) onto the GLW-2 and Figure 4.17 presents these results graphically.

Table 4.4.13: The Results Summary of High Gas Injection Pressure onto the GLW-2				
Valve Description		Production Rate (lit/min)	% of Increase in Production Rate	Well-Head Pressure (psi)
% of Opening	Port Size (mm)			
4	0.25	6.9	N/A	0.6
15	0.95	7.3		0.5
30	1.91	9.8		0.5
50	3.18	8.3		0.5
65	4.13	6.4		0.6
80	5.08	6.1		0.6
100	6.35	4.1		0.7

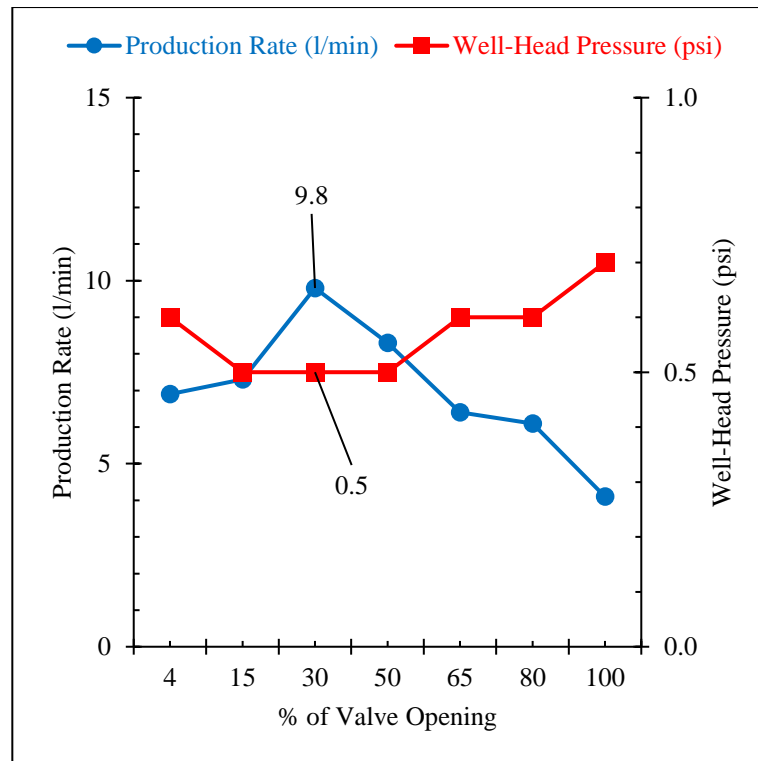


Figure 4.17: Effect of High Gas Injection Pressure (87 psi) for GLW-2

Results shown in Figure 4.17, presents the maximum production rate of 9.8 lit/min could be achieved when the high gas injection pressure at 87 psi is used at 30% of the valve opening (or 1.91mm port size diameter). Also, the wellhead pressure reaches to the minimum value of 0.5 psi in which high-pressure drop between the reservoir pressure and the top surface will occur. Opening the valve port size, injects too much gas and the flow rate then decrease sharply to the minimum level of 4.1 lit/min in which the well-head pressure is at the maximum value of 0.7 psi. This issue, as explained previously, caused by injection of too much gas into the system in which the gas bubbles within the production tubing are generating rapidly and since the injection of the pressure is higher, therefore, they combined together faster than injection at low pressure. Thus the complete blockage will occur and the production will stop.

Figure 4.18 shows the comparison of the all three gas injection pressures onto the GLW-2.

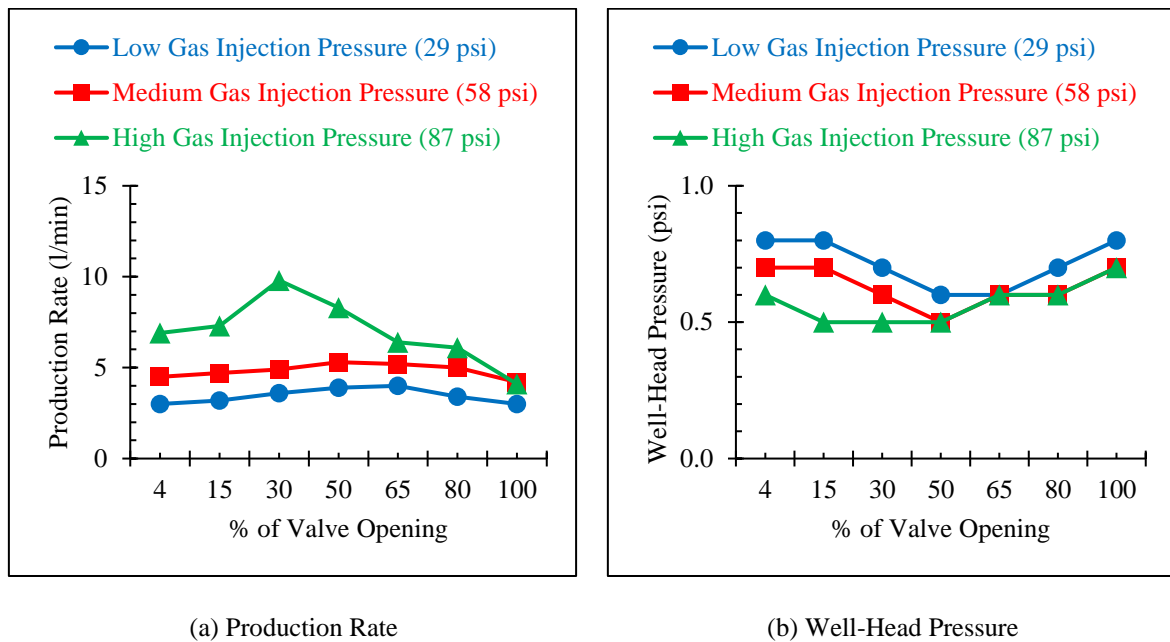


Figure 4.18: Summary of Different Gas Injection Pressures on Production Rate for GLW-2

The comparison results of the production rate with injection different gas pressures show that using a low gas injection pressure assist the well to be producible (see Figure 4.18 (a) and it will keep the well-head pressure almost constant (see also Figure 4.14 (b). This result also demonstrates that the optimum well-head pressure should be within the range of 0.5 to 0.6 psi in order to achieve maximum production rate for different gas injection pressures. However, applying the gas injection at lower pressure will keep the production rate almost constant in which the valve port size can be controlled and monitored easily compare it with high- pressure gas injection which shows that the production rate will be increased from 4% to 50% opening and after that the reduction of flow rate will occur.

4.4 Economic Consideration of Gas Injection Pressure

Global demand for petroleum was never decreased. Since it is finite and scarce natural resources, petroleum industry players are looking forward to more efficient technologies in all aspects of optimum production. During the initial stage of production, the bottom-hole pressure (BHP) in the oil reservoir is sufficient to force the flow of oil to the surface naturally. However, as time goes by, the internal pressure of depleted reservoir can force only a fraction of it. Thus, the use of smart technique becomes essential.

Oil well economic evaluation is based on the data of the whole process of oil production and considering yield, invest, cost and well type, etc. Furthermore, the economic evaluation results can help to determine the project benefits. In this study, the input and output method was carried to determine the benefits of utilizing the smart gas lift valve for both types of wells in the natural flow wells and gas lift wells. As mentioned previously, the gas lift can be applied to both dead wells and natural flowing wells.

It can help the dead wells to return back to production and accelerate the production of the natural flowing wells. In this study, the economic evaluation study was carried in order to evaluate how smart gas lift valve can play a vital role in accelerating production, in natural flow and gas lift wells. Table 4.14 illustrates the Economic Evaluation of Gas Injection Pressures onto the natural flow well (NFW-1).

4.4.1 Economic for Natural Flow Wells

Table 4.4.14: The Economic Evaluation of Gas Injection Pressures onto the NFW-1				
Injection Pressure	Production Rate (bbl/day)		Production Rate Improvement (bbl/day)	Profit Income (\$/day) (Oil Price \$37/bbl)
	Before Gas Injection	After Gas Injection		
Low (29 psi)	227.5	251.2	23.7	\$876.90 / day
Medium (58 psi)		282.1	54.6	\$2020.20 / day
High (87 psi)		282.1	54.6	\$2020.20 / day

The analysis suggests (as shown in Table 4.14) that the oil price plays a critical role in the decision making the process for smart gas lift installation. Table 4.14 shows the improvement of production rate when the gas injection was applied by 58 psi this led to enhance the production to 54.6bbl/day from 227.5 before the injection to 282 after the injection which made \$2020.20 profit income per day for the studied well. When compared the results to select the optimum injection pressure it is clear; see that the increase the injection pressure from 58 psi to 87 psi leads to that insignificant improvement in production flow rate. Therefore, it is clearly seen that the optimum injection pressure for this well is 58 psi that led to \$2020.20 profit income per day for the studied well.

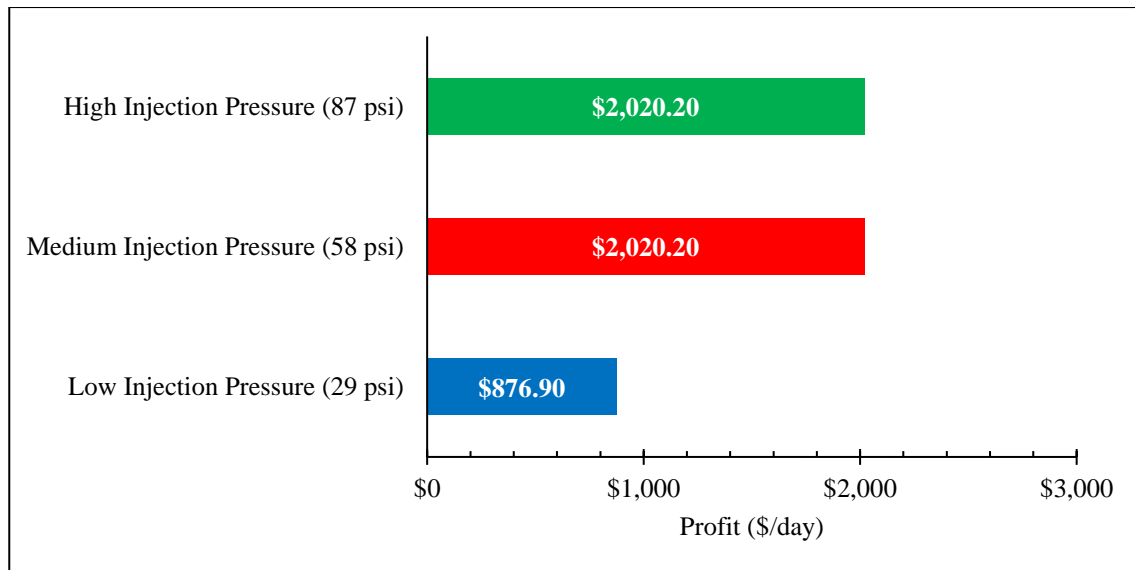


Figure 4.19: Economic Evaluation of NFW-1

As shown in Figure 4.19, the overall result indicates that increasing the injection pressure from 58 psi to 87, psig did not provide enhancement in profit(\$/day) for this well. Furthermore, shown in Figure 4.9 (a) the overall result indicates that the injection pressure plays an important role in decreasing bubble size gradually and stability the upward flow. This would restrict the development of flow. However, increase in the injection pressure is limited as it required huge gas compressor units (gas compressors) and thus would have a financial impact. However, compressor selection is dependent on many factors; reliability initial cost of installing, fuel consumption, and efficiency maintenance cost weight and space limitations, the length of run between planned shutdown, required discharge pressure, capacity, machine duty, operating environment, depth of the well and the fluid level in the tubing string. The attained results indicated that gas lift optimization process is inevitable for obtaining high oil production rates and several variables should be considered the gas injection pressure, gas injection rate and the valve port size.

Table 4.15 illustrates the effect of the gas injection rates on production rate for the different pressure 29, 58 and 87 psi for NLW-2.

Table 4.4.15: The Economic Evaluation of Gas Injection Pressures onto the NFW-2				
Injection Pressure	Production Rate (bbl/day)		Production Rate Improvement (bbl/day)	Profit Income (\$/day) (Oil Price \$37/bbl)
	Before Gas Injection	After Gas Injection		
Low (29 psi)	91.0	130.1	39.1	\$1446.70 / day
Medium (58 psi)		141.1	50.1	\$1853.70 / day
High (87 psi)		166.5	75.5	\$2793.50 / day

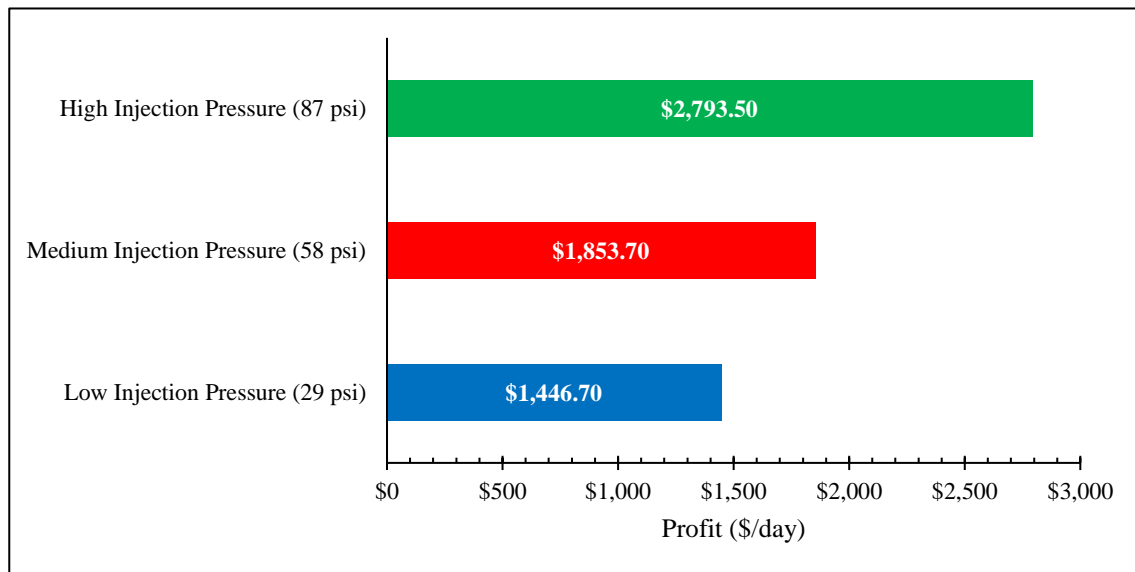


Figure 4.20: Economic Evaluation of NFW-2

The analysis evaluation (as shown in Table 4.15) shows the improvement of production rate when the gas injection was applied by 58 psi this led to enhance the production to 50.1 bbl/day from 91.0 before the injection to 141.1 after the injection which made \$1853.70 profit income per day for the studied well. The overall result indicated that the increase the injection pressure from 58 psi to 87 psi leads to that insignificant improvement in

production flow rate. Therefore, it is clearly seen that the optimum injection pressure for this well is 87 psi that led to \$2.793.40 profit income per day for the studied well. Furthermore, the results indicated that injection pressure gave high production in the well which has low productivity index.

4.4.2 Economic for Gas Lift Wells

The reason for increased expenditure for gas lift facilities is the percentage of oil produced by this technique. The facility drives gas lift in the sense of providing the gas pressure and rate but also in terms of the capital cost for the gas lift compressors. Of course, most the production facilities are installed for the natural flow wells, only the smart gas lift completion, gas distribution, and control system and gas dehydration unit. Although the emphasis is on the capital expenditure for the facilities, the sum total of well completion and drilling could equal the surface facility cost, or depending on the field location could far exceed the facilities cost. Figure 4.21 shows the estimated cost for an onshore field and for an offshore field [38].

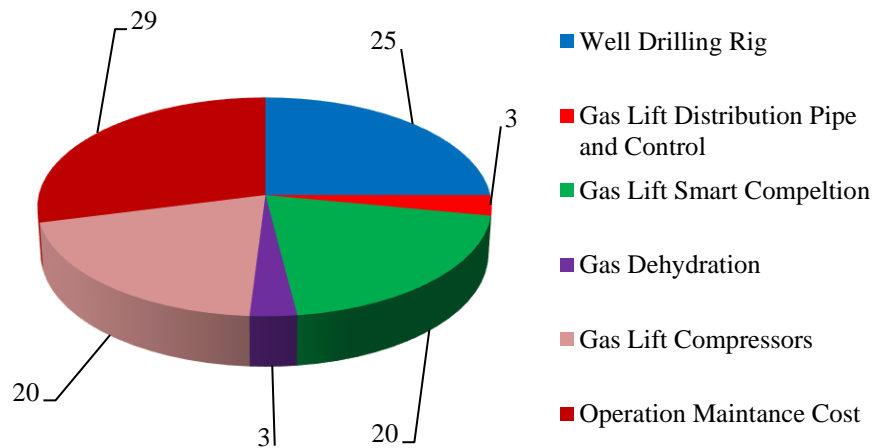


Figure 4.21: Estimated cost % for smart well Field [38]

The increase in injection pressure has a positive effect on the steady state of the well performance. This is because it increases the air injection rate and produces larger initial bubble sizes which cause faster flow movement out of the transparent pipe. It is clearly seen that the increase in injection pressure has a considerable effect on the well performance productivity. As shown in Figure 4.22, the overall result indicates that the high injection 87 psi the production rate increases to the maximum value of 165.6 bbl/day which made \$6.127.20 profit income per day, at medium injection pressure 58 psi the production rate will then rise to the maximum value of 149.20 bbl/day which provides \$5.520.40 profit income per day, and low injection pressure 29 psi the production rate will then rise to the maximum value of 127.4 that gives the highest profit \$4.713.80 profit income per day. Table 4.16 illustrates The Economic Evaluation of Gas Injection Pressures onto the Gas Lift Well (GLW-1).

Table 4.4.16: The Economic Evaluation of Gas Injection Pressures onto the GLW-1				
Injection Pressure	Production Rate (bbl/day)		Production Rate Improvement (bbl/day)	Profit Income (\$/day) (Oil Price \$37/bbl)
	Before Gas Injection	After Gas Injection		
Low (29 psi)	0	127.4	127.4	\$4713.80 / day
Medium (58 psi)		149.2	149.2	\$5520.40 / day
High (87 psi)		165.6	165.6	\$6127.20 / day

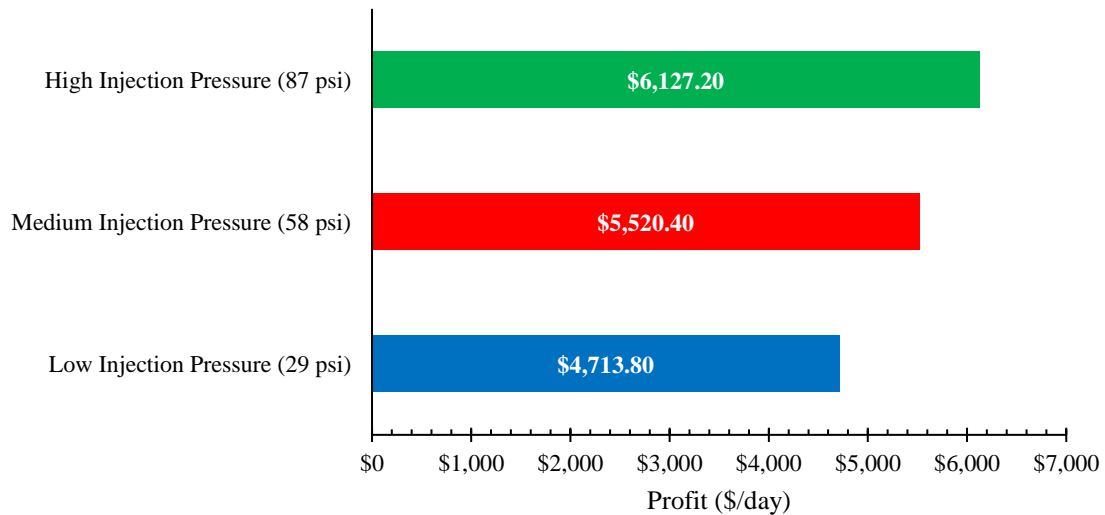


Figure 4.22: The Economic Evaluation of the GLW-1

As shown in previous Figure 4.18(b), the overall result indicates that the low injection 29 psi The production rate increases to the maximum value of 5.2 l/min which made \$1.346.80 profit income per day, at medium injection pressure 58 psi the production rate will then rise to the maximum value of 5.3 lit/min which provides \$1.783.40 profit income per day, and high injection pressure 87 psi the production rate will then rise to the maximum value of 19.8 l/min that gives the highest profit \$3.300.40 profit income per day as can be seen in Table 4.17 and Figure 4.23.

Table 4.4.17: The Economic Evaluation of Gas Injection Pressures onto the GLW-2				
Injection Pressure	Production Rate (bbl/day)		Production Rate Improvement (bbl/day)	Profit Income (\$/day) (Oil Price \$37/bbl)
	Before Gas Injection	After Gas Injection		
Low (29 psi)	0	36.4	36.4	\$1349.80 / day
Medium (58 psi)		48.2	48.2	\$1783.40 / day
High (87 psi)		89.2	89.2	\$3300.40 / day

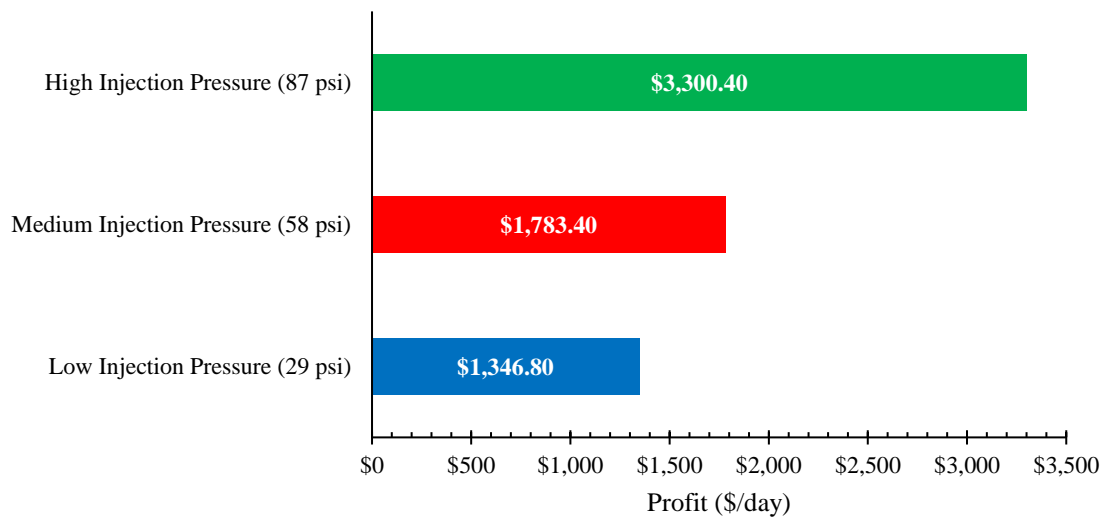


Figure 4.23: Economic Evaluation of GLW-2

In the traditionally gas lift, changes in the gas rate at the surface cause dynamic changes in the well starting at the bottom and working their way up to the surface. Since the typical oil reservoir can be more than a mile below the wellhead, many subsequent and sequential upsets can be induced before the previous ones reach the surface. As a result, the well is in a constant state of instability. And, fluid production is always less than optimal in an unstable well. In order to efficiently stabilize gas injection rates in the field, the gas lift

valve must be installed and implemented with this valve the system achieves the final goal by maintaining a constant gas lift injection rate, gas injection pressure in real time.

The smart gas lift valve has the potential to reduce the operational costs by reducing or eliminating the expensive intervention and workover costs. Implementing intelligent completion can results also in lower capital expenditure since it provides better control of the injection gas rate allows reaching the same target production. Table 4.18

summarizes the advantages of smart gas lift system and the disadvantages of traditional gas lift.

Table 4.4.18: The advantage of smart gas lift system and the disadvantages of traditional gas lift.

Disadvantage of traditional gas lift	Advantage of intelligent system
<ol style="list-style-type: none"> 1. Unsafe 2. Increase operational and gas lift gas cost 3. lift gas is not actively control 4. Only estimate the flow rate that delivered 5. fluctuation in gas lift supply 6. increase down time and injection gas 7. loss of production 8. unstable production 9. Lack of time. 10. Lack of Integration between subsurface-surface 11. Poor decision making 12. Complex and risky operation. 13. Poor reservoir management 14. Multipoint of injection 15. Gas lift valve damage due to flow erosion increase. 	<ol style="list-style-type: none"> 1. More safe and Low risk 2. Ability to respond immediately action. 3. Saving on intervention cost 4. Good reservoir and production management. 5. Improve oil production performance 6. Real time analysis in early stage 7. Maximize facilities performance and life 8. Eliminates multiple slick line trips. 9. Using real time data set to improve gas lift design performance. 10. High initial installation cost. 11. Increase reserves and enhanced environmental impact. 12. Real time picture of all gas lift valves 13. Continuous performance optimization

4.5 Limitation of Research

Numerous reasons some legitimate and some lame; have been offered they years; for example; we don't have the correct data. The data are either low quality or insufficient quantity or taken too infrequently. Conversely, sometimes the claim is that there is too much data and we do not have an appropriate system to handle it.

Lack of resources (financial and time) to focus on real-time optimization

- i. It looks like a good idea, but would possibly be too expansive.
- ii. Lack of formal education in petroleum optimization.
- iii. We don't have the integrated software tools to correctly model.
- iv. Improving the above items will help us build greater oil business.

Summary

- It can be concluded that smart gas lift valve is capable of aiding faster continuous flow gas lift optimization process as it can be used to determine the optimum flow rate in gas lift system.
- An obtaining the optimum gas injection rate is important because although oil production increase as gas injection increased, injection of excessive gas not only will reduce production rate but also increase the operation cost due to high gas prices and compressing costs.
- Wellhead pressure is transmitted to the bottom of the hole, reducing the differential into the wellbore. Thereby reducing production and at the same time increasing injection gas requirements, so low wellhead back-pressure is of a prime importance, as it allows increased draw down, enhanced gas lift efficiency and thereby production can be increased, and lift power decreased.
- The results prove that the wellhead pressure has a major influence on the gas lift performance and also prove that a smart gas lift valve can help to improve gas lift performance by controlling gas injection from downhole. Obtaining the optimum gas injection rate is important as a result of excessive gas injection declines the

production rate and consequently increases the operational cost as shown in Figure 4.3.

- Results shown in Figure 4.8, presents the maximum production rate of 18.3 l/min (with 83% improvement on production) could be achieved.
- When the gas is injected at high pressure, a slight increase in the valve port size can block the production tubing due to the generating of the too much gas bubbles and rapid increase of wellhead pressure. Therefore using the novel method of gas injection using a smart gas lift valve can assure the user to control and monitor the valve port size from the surface at all the time and reduce or increase the valve port size as required.
- The experimental results were validated with Vogel Correlation that shown in Figure 4.10 that indicated at low injection pressure gives more production rate this is due differential pressure between the reservoir pressure and well head pressure is very low.

CHAPTER 5

Simulation Study Utilizing PROSPER Software

5.1 Introduction

In this chapter, the experimental results for the well-1 has been modeled using PROSPER Software (Petroleum Experts 2010). As shown in chapter-3 Table 3.3, the well has been assumed to have 4 psi reservoir pressure and producing 25 l/min before applying gas injection technique. Actual PVT data has been entered into the model. Input data consisted of the deviation survey, downhole completion, geothermal gradient, and typical heat capability. Also, the air lift data was entered for the well and included air properties, the downhole tools, the inflow, and the outflow were demonstrated and the current gas lift design was then the existing gas-lift designs were studied and covered in this chapter. This results will be helped to build a production optimization in order to increase oil flow rate and reduce the operation cost also, the experiment are used to predicting accurate pressure and flow regime and determine the effect of water cut on production , depth of injection for this well.

Prosper is one of the most common software for petroleum manufacturing. It is the petroleum Experts Limited's advance production and systems performance analysis software. Prosper can help the production of reservoir engineering to predict tubing and pipeline hydraulics and temperatures with accuracy and speed. In addition PROSPER great sensitivity calculation enables current designs to be optimized and the effects of future variations in the system parameters to be assessed. Furthermore, PROSPER is a well performance, design, and optimization package for modelling most types of well configurations found in the worldwide oil and gas industry today and is designed to allow

building of reliable and consistent well models, with the ability to address each aspect of wellbore modelling via; PVT (fluid characterization), VLP correlations (for calculation of flow line and tubing pressure loss) and IPR (reservoir inflow) (Petroleum Experts, 2010).

5.2 Features in PROSPER Modelling Software

Features in the PVT section in PROSPER can compute fluid properties using standard black oil correlations. The black oil correlations can be modified to better fit measured laboratory data. Also in this section as well, PROSPER allows detailed PVT data in the form of tables to be imported for use in the calculations. PROSPER can also be used to model reservoir Inflow Performance Relationship (IPR) for single layer, multi-layer, or even multilateral wells with complex and highly deviated completions optimizing all aspects of a completion design including perforation details and gravel packing. Both pressure and temperature profiles in producing wells, injecting wells, across chokes and along risers and flow lines could be predicted by PROSPER

Options Summery

The option menu is used to define the characteristics of the well. In this work, the following options had been selected to define the well model accurately:

- Fluid: Oil and Water
- PVT Method: Black Oil
- Separator: Single Stage Separator
- Flow Type: Tubing Flow
- Well Type: Producer
- Emulsions: No
- Viscosity Model: Newtonian Fluid
- Lift Method: Gas lift

- Prediction: Pressure and Temperature (Offshore)
- Model: Rough Approximation
- Calculation Range: Full System
- Output: Show Calculation Data
- Well Completion: Cased Hole
- Gravel Pack: No
- Reservoir Inflow Type: Single Branch
- Gas Coning: No

System Summary (EXPER 24 06.SIN)

Done Cancel Report Export Help Datestamp Datestamp Comments

Fluid Description Fluid: Oil and Water Method: Black Oil Separator: Single-Stage Separator Emulsions: No Hydrates: Disable Warning Water Viscosity: Use Default Correlation Viscosity Model: Newtonian Fluid		Calculation Type Predict: Pressure and Temperature (offshore) Model: Rough Approximation Range: Full System Output: Show calculating data	
Well Flow Type: Tubing Flow Well Type: Producer		Well Completion Type: Cased Hole Gravel Pack: No	
Artificial Lift Method: Gas Lift Type: No Friction Loss In Annulus		Reservoir Inflow Type: Single Branch Gas Coning: No	
User information Company: University of Salford Field: Gas lift optimization Location: Spay lab. Well: Experiment Results Platform: Analyst: MOHAMED ABDALSADIG Date:		Comments (Ctrl-Enter for new line) 03 Aug 17 19:58	

Figure 5.1: System Summary

5.3 Experimental Well Completion

Actual experimental data was entered into the model. Input data consisted of the deviation survey, down-hole completion, geothermal gradient, and average heat capacities. Table 7-1 show the experiment completion equipment, measured depth, transparent pipe inside diameter and roughness.

Table 5.1The Experiment Completion

The Experiment Completion Equipment	Items	Measured Depth feet	Inside Diameter inch	Tubing inside Roughness
Manifold	1	0		
choke	1	0	1.1	
Xmas Tree	1	0		
Tubing	1	6.561	2.5	0.0006

Air properties and water salinity were enters to the mode as can be seen in table 5.2

Table 5.2: PVT Data

Parameters		Unites
GOR	0	Scf/stb
Oil gravity	10	API
Gas gravity	1	Sp. gravity
Water salinity	0	ppm
H2s	0	percent
Co2	0	percent
N2	0	percent

Table 5.3: Pressure and Temperature Input Data

Temperature (deg. F.)		Pressure psig
From	65	0
To	75	10
Number of steps	1	15

Table 5.4: Air Lift Input Data

Parameters		Unites
Gas lift gravity	1	Sp. gravity
Mole percent H ₂ S	0	percent
Mole percent CO ₂	0	percent
Mole percent N ₂	0	percent
GLR Injected	0	Scf/stb
Gas lift valve depth measured	6.233	Feet
Gas lift method	Fixed Depth of injection	feet

5.4 Experimental Model Construction

The system has been modeled by using PROSPER software (Petroleum Experts 2010). Actual experimental data were entered into the model. Input data including the deviation survey, downhole completion, geothermal gradient, and the gas-lift data were used for the assumed well. First, the downhole equipment and inflow were modeled, and then the existing gas-lift designs were studied. Figures 5.4 and 5.5 illustrated the model in software.

GASLIFT INPUT DATA (EXPER 24 06.SIN)		
Done Cancel Export Report Help		
Input Data		
GasLift Gas Gravity	1	sp. gravity
Mole Percent H2S	0	percent
Mole Percent CO2	0	percent
Mole Percent N2	0	percent
GLR Injected	0	scf/STB
Gas Lift Method	Fixed Depth of Injection Optimum Depth of Injection Valve Depths Specified	
Gaslift Details		
Gaslift Valve Depth (Measured)	6.233	feet

Figure 5.2: Gas lift input data

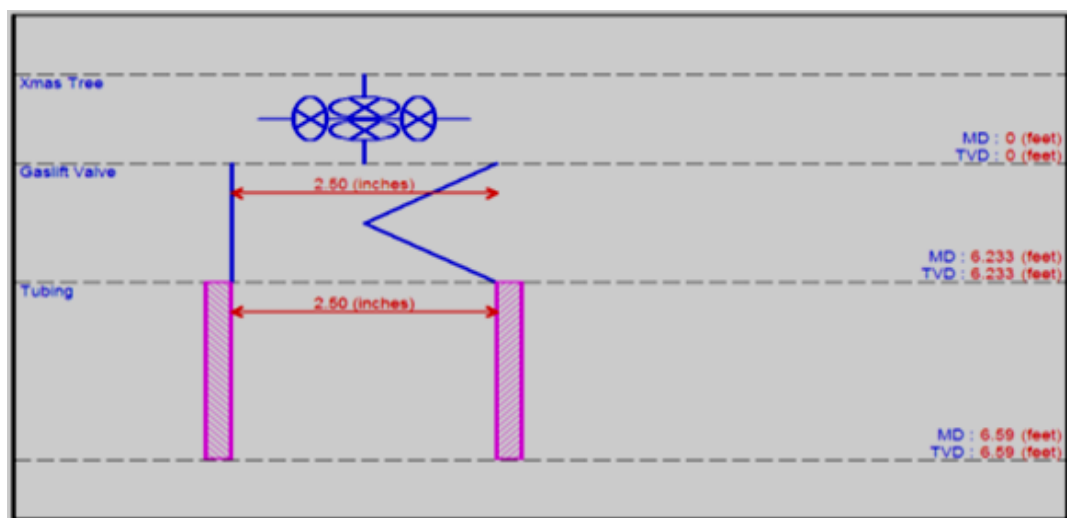


Figure 5.3: Well Completion From PROSPER

5.4.1 Experimental Operating Point

The experimental operating point is the point at which the forces acting on a tubing string suspended in a live wellbore are equal under these conditions, combining the tubing performance curve through a curve reflecting the inflow performance classifies the working point. Optimum liquid production is achieved at this point

To calculate the well production rate, the bottom-hole pressure which simultaneously satisfies both the IPR and VLP relations is required. By plotting the IPR and VLP in the same graph, the production rate can be found. The system can be described by an energy balance expression, simply the principle of conservation of energy over an incremental length element of tubing. The energy entering the system by the flowing fluid must be equal to the energy leaving the system plus the energy exchanged between the fluid and its surroundings. Fig. 6 illustrates that performance of the corresponding well is satisfactory at pressure 4 psig and production rate 137 bbl. / day. With well head pressure 1 psig and reservoir pressure 4 psi. Figure 5.6 illustrates the relationship between inflow and outflow by using experimental data.

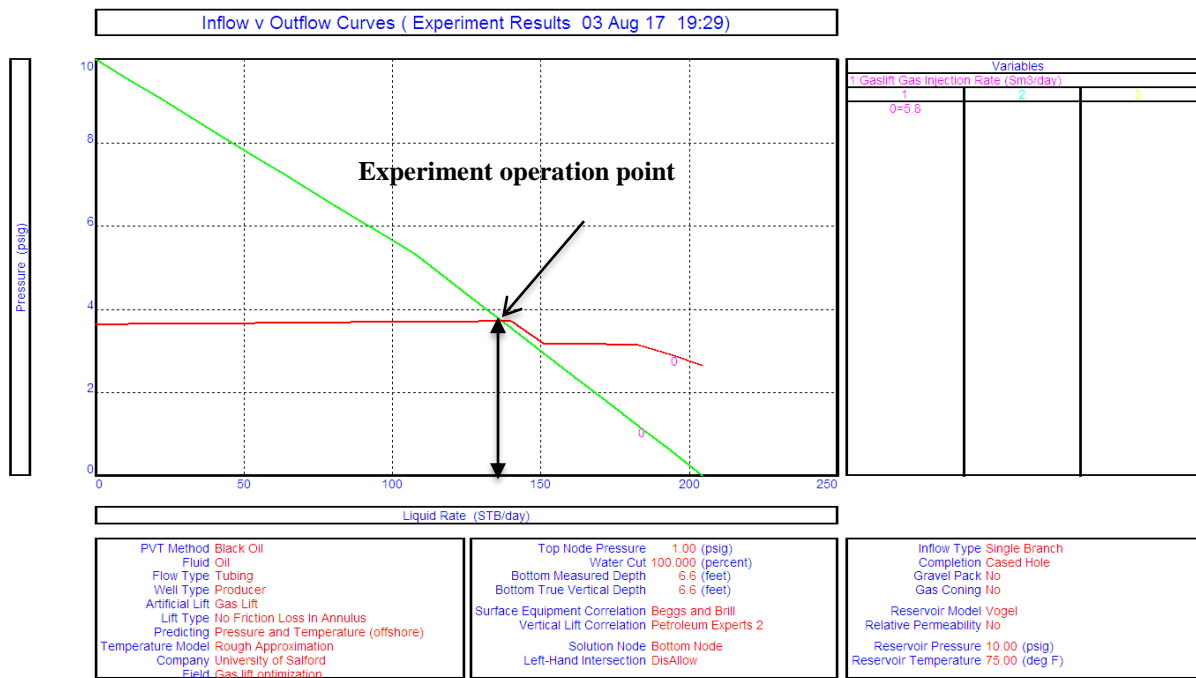


Figure 5.4: Inflow and out Flow Relationship

Predicting Accurate Pressure Gradient and Flow Regime

By forecasting correct temperature-pressure profiles in flowing wells one can expect that accurate pressure profiles in flowing wells can importantly recover the design of production services in petroleum engineering. Temperature profile can assist in determining perfect two-phase-flow pressure-drop calculations that in turn can increase an artificial-lift system design. Gas-lift design can be improved by more accurately forecasting the temperature at valve depth. The table 7-5 illustrates the pressure profile and flow regime types from bottom of the tubing to the manifold. From Table 7-5 and Figure 7-7 it is clearly shown that the gas flow gradient is 0.25 psi/ft. and the water gradient is 0.4491psi/ft. The results shows the fluid gradient 0.4097 at the bottom which for water gradient and gas gradient 0.25 at the top , type of flow regime was bubble flow.

Table 5.5: Predicting Accurate Temperature Pressure Profiles

Bottom Measured Depth	Pressure	Gradient	Flow regime
feet	psig	Psi/ft.	
0	1.00	0	Manifold
0	1.02	0.25	Choke
0	1.02	0.25	Well head
3.1	2.29	0.469	Bubble
6.2	3.56	0.487	Bubble
6.4	3.63	0.4096	Bubble
6.6	3.71	0.4097	Bubble

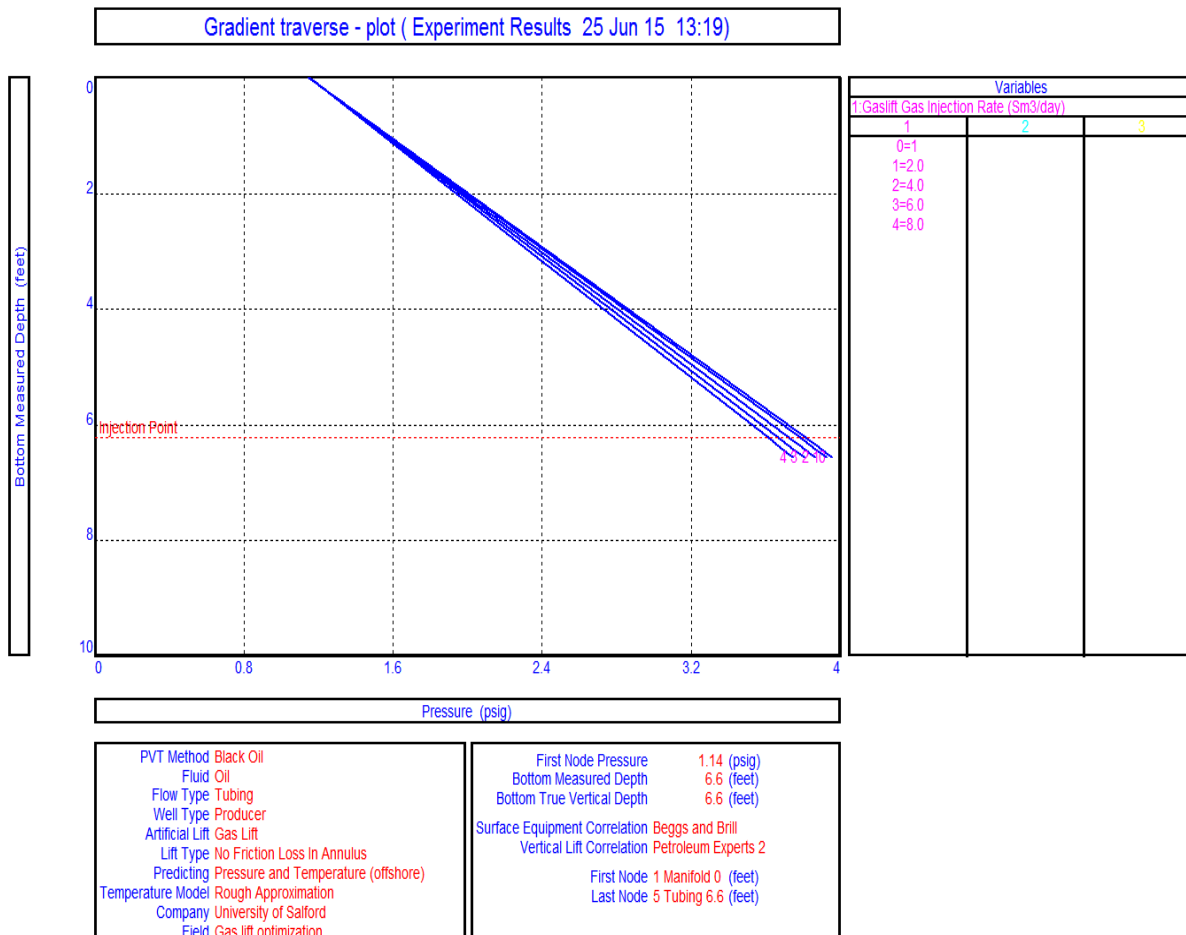


Figure 5.5: Experiment Gradient Result

5.4.2 Point of Injection

In each gas lift steady state design, the points of injection has to be determined the first point of injection has to be designed for kick-off. It means that at an early time, when the

tubing is full of liquid and the annulus is charged with high-pressure gas, the gas pushes the liquid out of tubing through U-tube effect which means that a high-injection gas pressure is needed to force the gas into the tubing. The necessary pressure is designed dependent on the gas density inside the annulus and the density of the fluid inside the tubing at a distance from the valve. . Figure 5.10 shows the experimental gas lift depth and the point of injection.

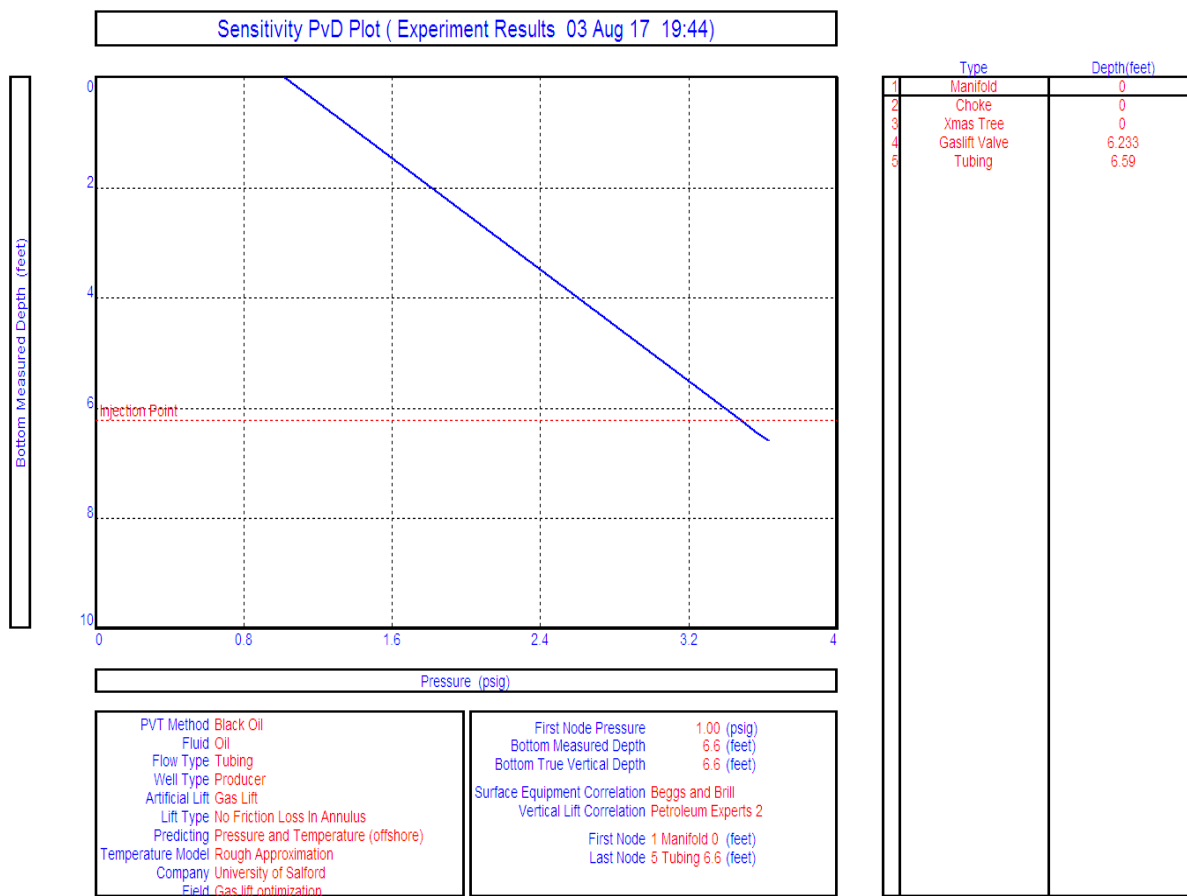


Figure 5.6: Shows the Experimental Gas Lift Depth

The depth of injection is administered by the existing compressor discharge pressure - Hydrostatic pressure of fluid in the well - Tubing/well head pressure - pressure loss through gas lift valve gas gradient. There is a balance in setting parameters which result in a single point injection system for which a maximum production rate is possible. In this

study, three different depths 2, 4 and 6.2 ft. were carried out to investigate the effect of change of depth of injection on well production performance. As shown in figure 7.4 below the injection sensitivities, the far injection of gas lift gas rate requires raising the liquid rate. This happens because, when gas is injected at a deeper point, this will result in a further reduction in fluid column hydrostatic pressure inside the vertical tubing. As a consequence of lightening the fluid, the hydrostatic pressure will decrease resulting in an improvement to bottom hole flowing pressure.

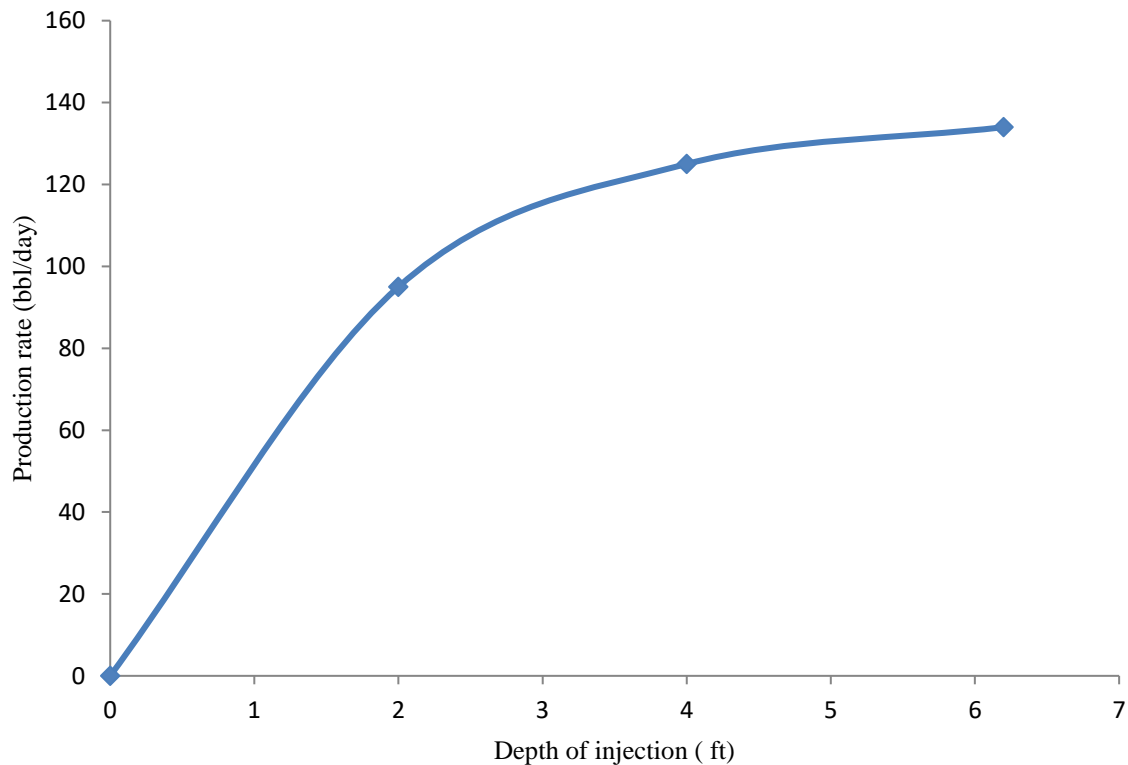


Figure 5.7: Injection Pressure Depth Effect on Liquid Flow Rates

From this Figure 5.11, it is clearly seen that an increase in the depth of injection from 4 ft. to 6.2 ft. led to insignificant improvement on liquid production from 125 to 134 STB/day.

5.4.3 Determination of the Depth of the Operating Point Of Injection

The initial stage in the design of a gas lift well is finding out the optimum distance of the working valve that, as explained earlier, is the final point of injection as soon as the well has been unloaded. This can be completed by the following processes that (with a few minor variations) can be applied to all kinds of gas lift valves. Collected with the determination of the injection point depth, the production liquid flow rate and the required injection gas flow rate are simultaneously designed. The key objective of this step is to locate the operating point of injection as deep as the available surface injection pressure permits it to be. The deeper the point of injection is, the more efficient the gas lift technique develops because a larger drawdown can be done. Furthermore, it is not always possible to inject gas at the deepest point available in the well because of one, or several, of the following reasons:

- The available injection pressure might not be large enough.
- The maximum gas flow rate might be limited.
- Mandrels and/or gas lift valves might not be able to withstand downhole conditions at great depths

5.4.4 Reservoir Pressure Effect

The delivery of fluid from the reservoir to the surface requires work to be done. In this study different static pressures are simulated to investigate and evaluate the effect to changes in reservoir pressure on production flow rates and economic analysis has been carried out to predicate the experimental reservoir pressure. Figure 5.12 illustrates the effect of the reservoir pressure in a well production rate.

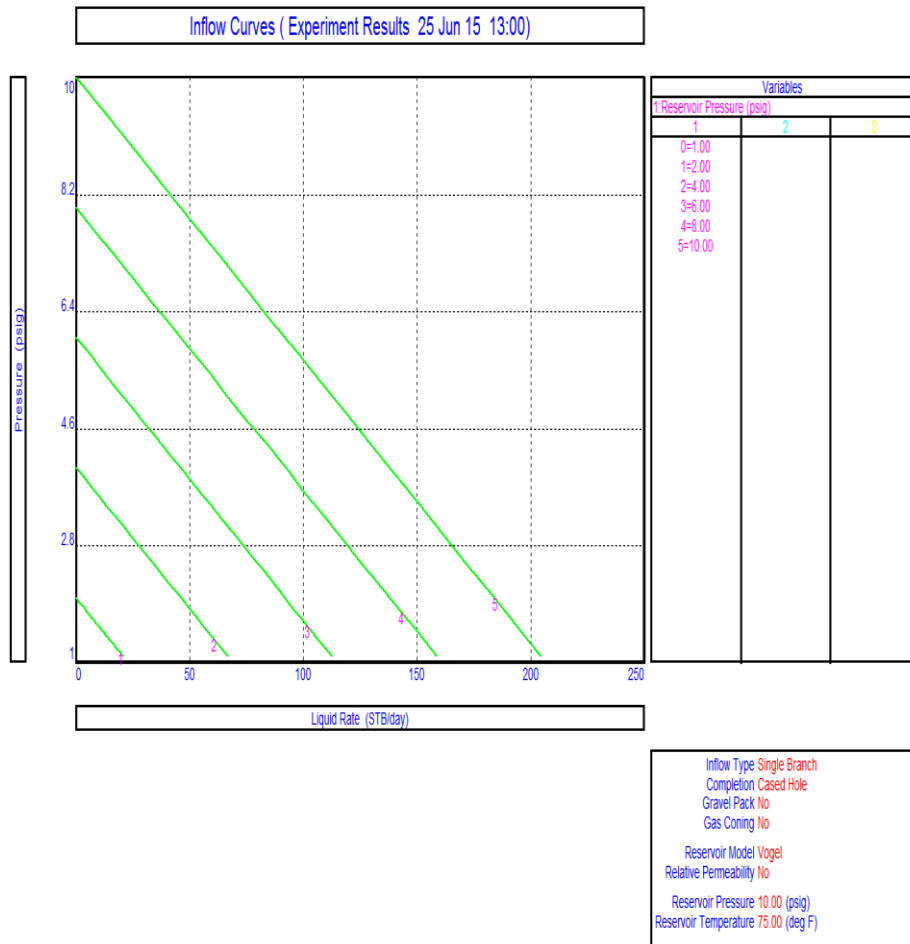


Figure 5.8: The Effect of Reservoir Pressure on Liquid Flow Rates

Figure 5.12 illustrates that change in the reservoir pressure leads to a change in the liquid production rate. It is clearly seen that the well cannot be produced at low reservoir pressures from 1 to 4 psi. The economical reservoir pressure is 4 psi.

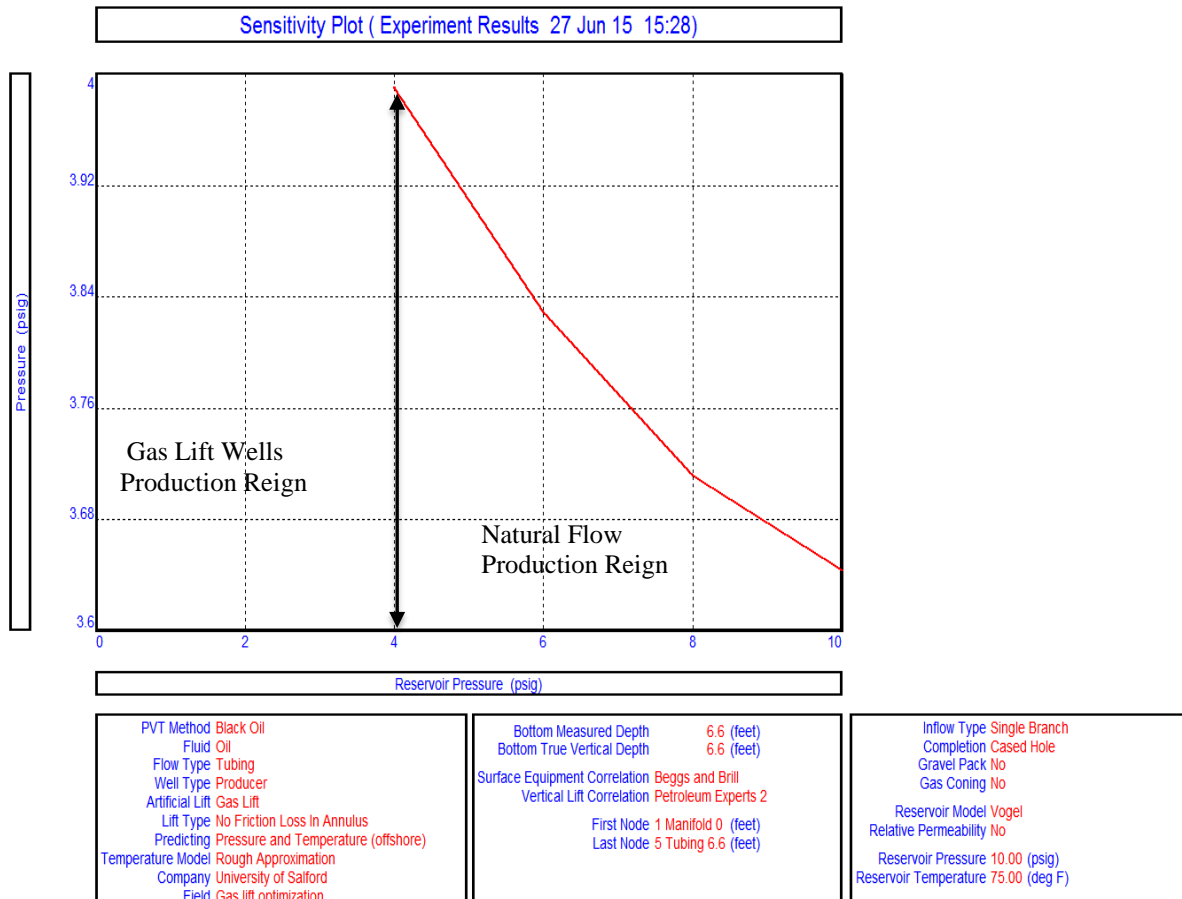


Figure 5.9: The Reservoir Sensitivity Analysis

From Figure 5.13 is clearly seen that the well cannot be produced at low reservoir pressure from 1 to 4 psi. And the economic reservoir pressure is 4 psi. Therefore, reservoir pressure is so important factor for gas lift design.

5.4.5 Pressure Effect on Well Head Pressure

An increase in the wellhead pressure ordinarily results in a disproportionate increase in the bottomhole pressure because the higher pressure in the tubing causes a more liquid-like fluid. In order to get the adequate injection air pressure that enters to the experimental system, air pressure regulator with range 0-11 psig was installed, and the supplied air was measured by air flow meter. Smart gas-lift valve was employed to control the air flow rate inside the transplant tube by opening the valve with the different port size based on the computer program. The results indicate that injecting a high amount of gas leads to the

increase in well head pressure which decreases the production rate. It is obvious that the well head pressure has a large influence on the gas-lift performance while it was shown that by using electrically controlled valve the production rate can be maximized. It is seen that the wellhead pressure has a large influence on the gas-lift performance, as lower wellhead pressure leads to lower bottom hole pressure required for a given production flow rate. However, raise wellhead tubing pressure due to high pressure gas let's reduce production rate. The results indicate that increase injection pressure from 29 psig to 58 psig leads to raising the wellhead pressure for all assumed well.

In order to investigate the effect of injection pressure on well head tubing pressure, different well head pressure of 0.5 to 8.0 psig was modelled in PROSPER Software and the results are presented in Figure 5.15 and Table 5.6. The results indicated that injecting high amount of gas increases the bottomhole pressure which leads to the reduction of the production rate. This is due to the high gas injection rate which causes slippage. In this case, gas phase moves faster than liquid phase, leaving the liquid phase behind and less amount of liquid will flow along the tubing. Hence, there should be an optimum gas injection rate. It is demonstrated that the well head pressure has a large influence on the gas-lift performance and it is shown that the use of an electric control valve can help to improve gas-lift performance.

Experimental results were validated with PROSPER Software and results were the same.

The results were plotted for each well with different flow rates. It indicated that big increase in the well head pressure stops the liquid flow. However, the well cannot be produced at well head pressure higher than 6 psig as shown in Figure 5.14.

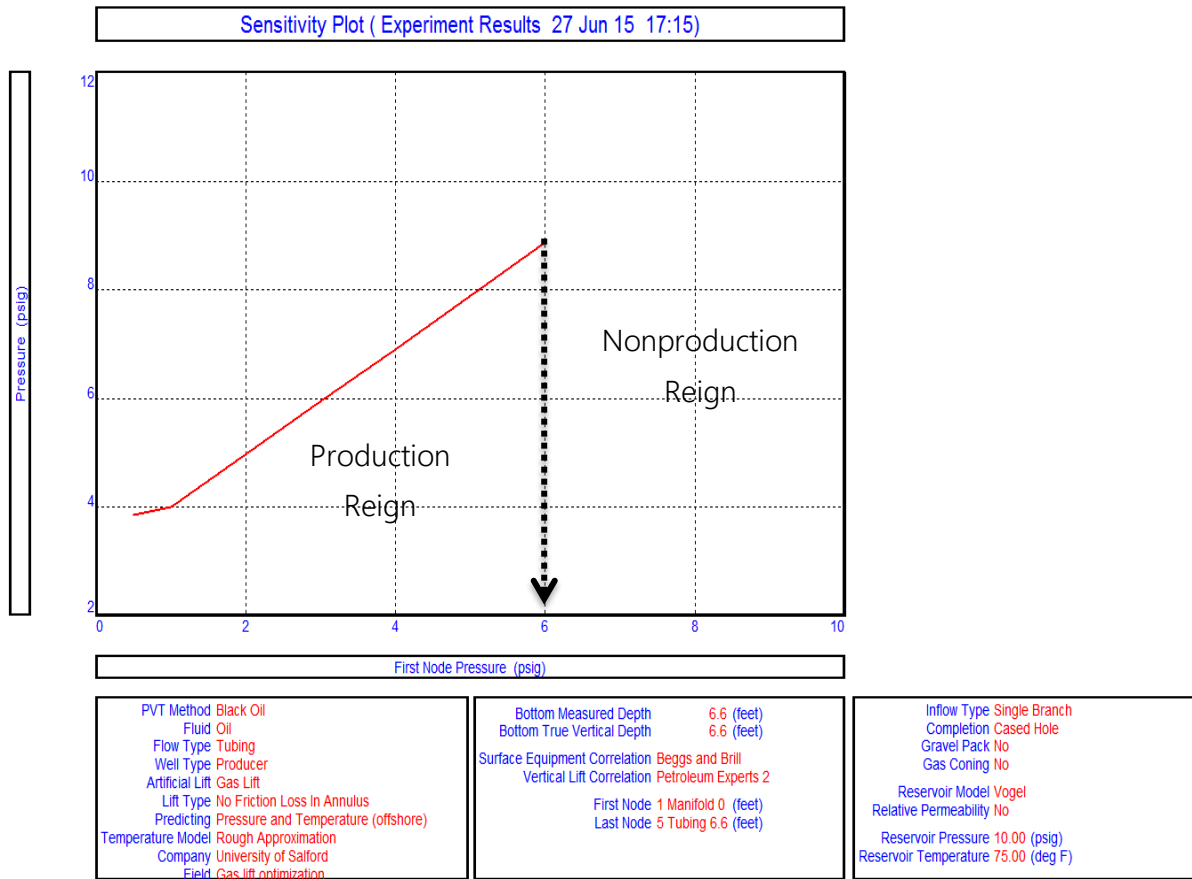


Figure 5.10: Pressure Effect on Well Head Pressure

It is obvious that the wellhead pressure has a large influence on the gas lift performance, as lower wellhead pressure leads to lower bottom hole pressure required for a given production flow rate. It is clearly indicated that as the injection pressure is increased the well head pressure started to increase gradually.

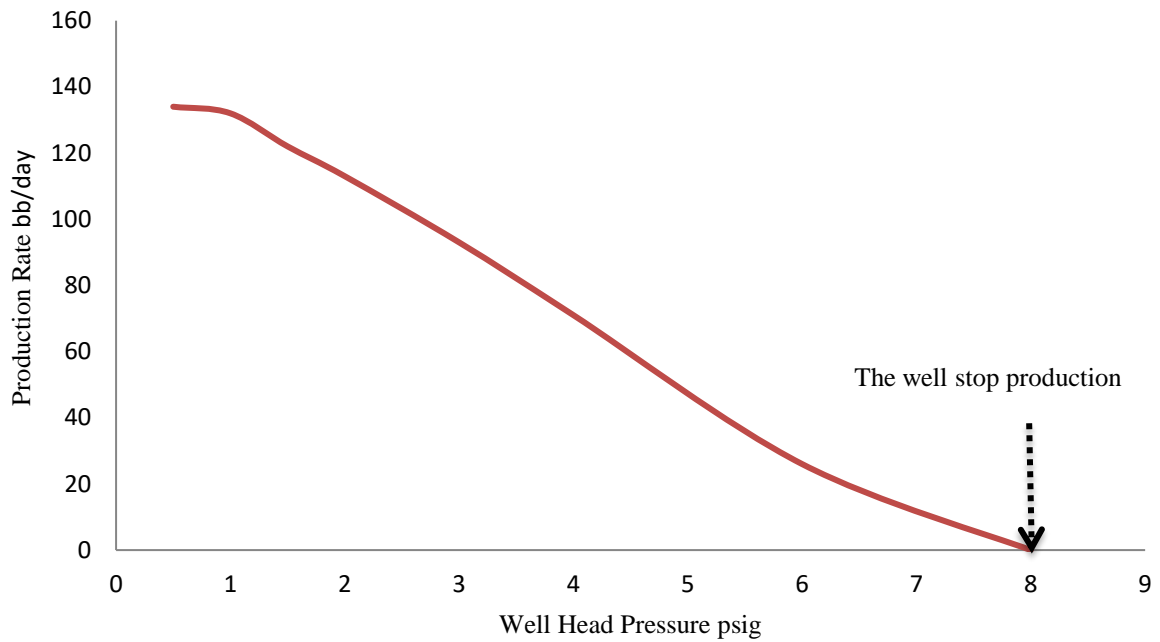


Figure 5.11: The Well Head Pressure on Production Flow Rate

Table 5.6: The Effect at Well head Pressure on Production Flow Rate

Wellhead Pressure psi	0.5	1.0	1.5	2.0	3.0	4.0	6.0	8.0
Liquid Flow Rate stb/day	134	132	122	113	93	71	26	0

The results from Figure 5.15 and Table 5.6 indicated that injecting high amount of gas increases the bottomhole pressure which lead to reduction of the production rate. This is due to the high gas injection rate which causes slippage. In this case gas phase moves faster than liquid phase, leaving the liquid phase behind and less amount of liquid will flow along the tubing. Hence, there should be an optimum gas injection rate. However, the gas injection rate must be controlled to achieve and maintain the critical flow. To determine the amount of gas to inject, it is necessary to find the critical velocity. Therefore, enough gas should be injected to keep the velocity above the critical level. In

this study smart gas-lift valve was used to control gas injection rate by opening the valve with different percentage using computer program.

5.4.6 Water Cut Effect

One of the most significant production problems in oil fields is high water production that may lead to wells dying and a decrease in an economical production period. With the increase of water production or decline of reservoir pressure, reservoir drawdown pressures a decrease that causes a drop in the oil production rate. However, water cut percentages should be forecast to control water amount that is produced. In this study, simulation, a base case forecast was undertaken at various operational conditions of reservoir pressures and different water cuts. Effect of water cut on gradient curve is expressed by the following equations.

$$\rho_1 = \rho_0(1 - f_w) + \rho_w \cdot f_w = \rho_0 + (\rho_w - \rho_0) \cdot f_w$$

Here, f_w is water cut. The equation shows that raised water cut results in increased water density that in its turn raises hydrostatic forces. As a result, pressure gradient and bottomhole pressure rise. Experiments results data were carried out to investigate the effect of water cut in the well performance. The results indicated that increasing water cut will lead to an increase in the interfacial tension which resulted in a decrease in the liquid flow rate. However, increasing water cuts results to an increase in liquid density, which in turn, raises hydrostatic forces and the bottomhole pressure. After matching PVT, VLP and IPR data, scenarios were made to use the model to perform a system analysis. The sensitivity test was carried out on the reservoir pressure for the effect of the water cut and decrease or increase in wellhead pressure. The increase in the water cut results in an increases water density that in its turn raises hydrostatic forces.

CHAPTER 6

CONCLUSIONS AND RECOMMENDATION

6.1 Conclusions

- In this study, a smart gas lift valve unit with the corresponding control line was experimentally simulated on a dedicated apparatus. This enables real-time data on the gas lift valve to the surface to be demonstrated and accordingly analysed.
- In this investigation, the port size of the gas lift valve was remotely adjusted from the assumed surface using the apparatus. A devoted computer program LabVIEW was also used in the determination of the gas passage through the smart gas lift valve, thus distilling the real time data.
- The result shown those optimizations are achievable at high gas injection pressure at 87 psi is used and when the valve is 15% open (or 0.95mm port size diameter). Also, the wellhead pressure reaches to the minimum value of 0.9 psi in which high-pressure drop between the reservoir pressure and the top surface will occur.
- Throughout this investigation, water was used as a working fluid since the column of corresponding water in petroleum production tubing has the highest hydrostatic pressure of 2.8 psig compared with crude oil. Hence, during the gas lift process crude oil will be less cumbersome to produce than water.
- Results shown in Figure 4.8, presents the maximum production rate of 18.3 lit/min (with 83% improvement on production) could be achieved. The results obtained experimentally were also used in constructing an economic analysis from the use of smart gas lift valve for different scenarios namely:
 - i. In gas lift natural flow: the flow rate can be enhanced from 91bbl/day to 166.5 bbl/day
 - ii. The gas lift wells: the flow rate can be increased from 'Zero' (or non-production) to 165.6 bbl/day
- Based on these results, the NPV of the gas lift natural flow will be approximate \$2793 on \$37 per barrel and for the gas lift well will be about \$6127.2

6.2 Future Work

The following are recommendations for future research:

- Mathematical modeling of gas lift valve design will also provide further information on valve performance.
- Since the gas lift method is one of the most widely used methods in solving production problems in the oil industry, a study in smart gas lift valve in dual completion is highly recommended to see if this method is suitable for a certain system.

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APPENDICES

Appendix-A: Excel sheet of data collection

pages

- Operation Condition and Results A-C
- Wells Economic Evaluation D

Appendix-B:

- Publications E

APPENDIX A: Excel sheet of data collection

Table 5.0.1: Appendix-A: NFW-1 Operation Condition and Results

Before the injection				After the injection								
Reservoir condition			Percentage of the valve opening	29 psig			58 psig			87 psig		
Water flow	Water pump rate	Production before the injection										
l/min	l/min	l/min	%	Production Rate l/min	Production Flow Pressure (Well Head Pressure) psig	Percentage of increase production %	Production Rate l/min	Production Flow Pressure (Well Head Pressure)	Percentage of increase production %	Production Rate l/min	Production Flow Pressure (Well Head Pressure) psig	Percentage of increase production %
25	4	25	4	26.1	1.3	4%	29.	1.2	16	29.3	1.0	17
			15	26.6	0.9	6	29.5	1.0	18	31.0	1.0	24
			30	27.0	0.9	8	31.0	1.0	24	28.7	1.0	15
			50	27.6	0.9	10	30.2	1.0	21	27.6	1.2	10
			65	27.0	0.9	8	30.0	1.0	20	27.2	1.2	9
			80	26.5	0.9	6	29.5	1.0	18	26.	1.4	4
			100	26	1.4	4	29.1	1.3	16	25.4	1.5	2

Table 5.0.2: Appendix-A: NFW-2 Operation Condition and Results

Before the injection				After the injection								
Reservoir condition			Percentage of the valve opening	29 psig			58 psig			87. psig		
Water flow qw	Water pump pressure	Production before the injection										
l/min	psi	l/min	%	Production Rate l/min	Production Flow Pressure Well Head Pressure) psig	Percentage of increase production %	Production Rate l/min	Production Flow Pressure (Well Head Pressure)	Percentage of increase production %	Production Rate l/min	Production Flow Pressure (Well Head Pressure) psig	Percentage of increase production %
10	2	10	4	13.7	1.0	37	14.5	1.2	45	15.0	1.1	50
			15.	14.1	1.0	41	15.3	1.1	53	18.3	0.9	83
			30.	14.3	1.0	43	15.5	1.0	55	15.6	1.1	56
			50	14.3	1.0	43	15.0	1.1	50	14.9	1.2	49
			65	14.	1.0	40	13.7	1.2	37	14.5	1.2	45
			80	13.1	1.0	31	13.0	1.2	30	15.0	1.4	50
			100	13.0	1.0	30	12.2	1.3	22	13.7	1.5	37

Table5. 0.3: Appendix-A: NLW-1 Operation Condition and Results

Before the injection				After the injection								
Reservoir condition			Percentage of the valve opening	29 psig			58 psig			87. psig		
Water flow	Water pump rate	Production before the injection										
l/min	psi	l/min	%	Production Rate l/min	Production Flow Pressure Well Head Pressure) psig	Percentage of increase production %	Production Rate l/min	Production Flow Pressure (Well Head Pressure)	Percentage of increase production %	Production Rate l/min	Production Flow Pressure (Well Head Pressure) psig	Percentage of increase production %
0	1.0	0	4	10.0	1.2		14.0	1.4		14.5		1.6
			15.	12.8	1.2		14.4	1.4		14.7		1.6
			30.	14.0	1.2		14.8	1.4		15.6		1.6
			50	16.0	1.0		16.4	1.1		18.2		1.2
			65	15.0	1.1		15.8	1.3		14.9		1.6
			80	14.1	1.1		15.0	1.3		12.1		1.6
			100	13.2	1.1		13.9	1.4		10.9		1.6

Table5.0.4: Appendix A: Wells Economic Evaluation

	Initial PR (bbl/day)	Low Injection Pressure (29 psi)			Medium Injection Pressure (58 psi)			High Injection Pressure (87 psi)		
		PR After Injection (bbl/day)	Improve PR (bbl/day)	Profit (\$/day)	Improve PR (bbl/day)	Improve PR (bbl/day)	Profit (\$/day)	Improve PR (bbl/day)	Improve PR (bbl/day)	Profit (\$/day)
NFW-1	227.5	251.2	23.7	\$876.90	282.1	54.6	\$2,020.20	282.1	54.6	\$2,020.20
NFW-2	136.5	178.4	41.9	\$1,550.30	202.9	66.4	\$2,456.80	211.1	74.6	\$2,760.20
NFW-3	91.0	130.1	39.1	\$1,446.70	141.1	50.1	\$1,853.70	166.5	75.5	\$2,793.50
GLW-1	0.0	145.6	145.6	\$5,387.20	149.2	149.2	\$5,520.40	165.6	165.6	\$6,127.20
GLW-2	0.0	36.4	36.4	\$1,346.80	48.2	48.2	\$1,783.40	89.2	89.2	\$3,300.40

Appendix-B: Publications